CA2ALQG 10
68R68-A
C.1

CA2 ALOG 10 1968R68-A
Report on an Application of Trans-Canada
Pipe Lines Limited Under the Gas 1
3 3398 00140 2246

LEGISLATURE LIBRARY
DEC 23 1974
EDMONTON
c1

LIBRARY
VAULT 19

REPORT ON AN APPLICATION OF TRANS-CANADA PIPE LINES LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

NOVEMBER 1968

< Alta

OIL AND GAS CONSERVATION BOARD
603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA

Digitized by the Internet Archive
in 2022 with funding from
Legislative Assembly of Alberta - Alberta Legislature Library

https://archive.org/details/ableg_33398001402246

REPORT ON AN APPLICATION OF TRANS-CANADA PIPE LINES LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

NOVEMBER 1968

OIL AND GAS CONSERVATION BOARD
603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA

Price $1.50

TABLE OF CONTENTS

Section		Page
I	INTRODUCTION..	1
	Appearances	2
	Date of Reserve Assessment and Period of Protection	1
	Standard Conditions of Measurement	3
II	SUBMISSION OF TRANS-CANADA PIPE LINES LIMITED...	4
	Reserves	5
	Reserves under Contract	6
	Deliverability	7
	Trend in Growth of Reserves	7
	Surplus	7
III	SUBMISSIONS OF INTERVENERS..........................	9
	The Alberta Division of the Canadian Petroleum Association	9
	Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited	9
	Chevron Standard Limited	10
	Imperial Oil Enterprises Ltd.	10
	Independent Petroleum Association of Canada	10
	Pan American Petroleum Corporation	11
	Pacific Petroleums Ltd.	11
	Peace River Mining & Smelting Ltd.	12
IV	MATTERS OF SPECIAL CONCERN..........................	14
	Probable Reserves	14
	Period of Protection	15
	Growth of Reserves	19

Section | Page

Daily and Annual Withdrawals 22

Fields not Subject to Contract 23

V FINDINGS.. 25

1. Established Reserves of Gas in Alberta 25

2. Trends in the Growth of Reserves of Gas in Alberta 25

3. Present and Future Requirements for Gas and the present Permit Commitments 26

4. The Meeting of Alberta's 30-year Requirements and present Permit Commitments, and the Resulting Surplus 27

5. Volumes under Contract and the Permit Volumes applied for 28

6. Application for the Removal of Additional Quantities and the Surplus which would Result if the Application were Granted 29

7. Other Amendments Applied for by Trans-Canada Pipe Lines Limited 31

8. Disposition of the Application of Trans-Canada Pipe Lines Limited 31

APPENDIX A.. A-1

The Established Reserves of Gas in Alberta

APPENDIX B.. B-1

The Trends in Exploration for and the Growth of Reserves of Gas in Alberta

APPENDIX C.. C-1

Alberta Gas Requirements and Permit Commitments

APPENDIX D.. D-1

The Meeting of Alberta's Requirements for Gas and the Present Permit Commitments, and the Resulting Surplus

Page

APPENDIX E. E-1

The Application for Authorization for the Removal of Additional Quantities of Gas and the Effect the Authorization would have on Surplus

APPENDIX F. F-1

Form of Permit

LIST OF TABLES

Table		Page
I	Appearances..................................	2
A-1	Established Reserves of Gas in the Province of Alberta, May 31, 1968......................	A-8
C-1	Summary of Forecasts of Alberta Gas Requirements for Period January 1, 1968 to December 31, 1997..........................	C-8
C-2	Permit Commitments..........................	C-9
D-1	Reserves and Reserve-Delivery Ratios of Fields Supplying Alberta's Requirements for Gas......	D-14
D-2	Summary of Reserves and Average Reserve-Delivery Ratio for all Reserves in the Province	D-18
D-3	Marketable Reserves Available in the Fields Included in Permits and Reserve-Delivery Ratios	D-19
D-4	Reserves Required to Meet Present Permit Commitments................................	D-25
D-5	Gas Surplus to Alberta's Requirements and Permit Commitments as of March 31, 1968 as Estimated by Trans-Canada.......................	D-26
D-6	CPA Probable Marketable Gas Reserves Gas Surplus to Alberta's Requirements and Permit Commitments as of December 31, 1967.....	D-27
D-7	Gas Surplus to Alberta's Requirements and Permit Commitments as of May 31, 1968 - As Estimated by the Board......................	D-28
D-8	Deferred Reserves............................	D-29
E-1	Proposed Changes in Marketable Reserves and Fields in the Trans-Canada Permit.............	E-5
E-2	Reserves Required to Meet Present Permit Commitments Including the Trans-Canada Applications................................	E-7
E-3	Gas Surplus to Alberta's Requirements and Permit Commitments as of May 31, 1968 as estimated by the Board........................	E-8

I INTRODUCTION

The subject application, made by Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956, was heard by the Oil and Gas Conservation Board on June 19 to June 21, 1968, with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and Vernon Millard sitting.

Trans-Canada's application asked that its Permit No. TC 67-7 be amended and that the permit and amendments be consolidated into a new permit. The proposed amendments, more fully set out in Section II of this report, would extend the term of the permit, increase the permit volumes and add to the list of fields and pools from which gas may be taken for removal from the Province.

Appearances

The persons listed in Table 1 appeared at the hearing.

Peace River Mining presented its submission at the request of the Board and dealt solely with its future requirements for gas in Alberta. The City of Calgary had not filed a submission in accordance with the notice of hearing, but finding itself opposed to the submission of the intervener, CPA, it sought leave to express this opposition which the Board granted.

The Alberta and Southern and Union Gas interventions had been filed for the purposes of cross-examination and argument only.

Date of Reserve Assessment and Period of Protection

The application contained Trans-Canada's reserve estimates as of March 31, 1968. At the hearing the Board stated that, for the

TABLE I

	Abbreviation of Name Used in Report	Represented by	Witnesses
Trans-Canada Pipe Lines Limited	Trans-Canada	F.P.Layton,Q.C. G.F.Hulme	G.A.Leslie, P.Geol. L.H.Larson, P.Geol. R.B.Trimble, P.Eng.
Alberta and Southern Gas Co. Ltd.	Alberta and Southern	D.R.Fenton, P.Eng.	
Alberta Division of the Canadian Petroleum Association	CPA	D.W.MacFarlane	G.A.Connell,P.Eng. J.B.McDonald,P.Eng. C.R.Mattinson
Canadian Western Natural Gas Company Limited and Northwestern Utilities,Limited	Utility Companies	B.V.Massie, Q.C.	J.H.Pletcher,P.Eng.
Chevron Standard Limited	Chevron	P.V.Malowany,P.Eng.	P.V.Malowany,P.Eng.
Imperial Oil Enterprises Ltd.	Imperial	D.E.Lewis,Q.C. and F.W.Kelly	E.W. Shaw
Independent Petroleum Association of Canada	IPAC	R.J.Abercrombie	C.Lee R.J.Abercrombie
Pacific Petroleums Ltd.	Pacific	J.L.Snith	G.C.Whittaker,P.Eng. K.A.Markland,P.Eng.
Pan American Petroleum Corporation	Pan American	G.E.Little	E.N.Bennett H.P.Nicholson J.E.Pease
Union Gas Company of Canada Limited	Union Gas	J.R.Smith,Q.C.	
Peace River Mining & Smelting Ltd.	Peace River Mining	Dr.C.P.Gravenor	Dr.C.P.Gravenor
City of Calgary and City of Edmonton	Cities	F.J.Fleming, Q.C.	D.L.Flock,P.Eng.
Board Staff		N.A.Macleod, Q.C. N.J.Lashuk, P.Eng. F.Phillips, P.Eng. G. C. Watkins	

purpose of the application, it proposed using all data related to reserves available to the Board to May 31, 1968 and determining the reserves of the Province as of that date.

The period for which the Board has assessed the requirements of the Province and permit commitments is 30 years commencing June 1, 1968.

Standard Conditions of Measurement

In this report, unless otherwise stated, volumes of gas given are those at the standard conditions of 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Where reserves of gas are referred to herein, it means, unless otherwise specified, marketable reserves.

II SUBMISSION OF TRANS-CANADA PIPE LINES LIMITED

Trans-Canada applied for the amendment of Permit TC 67-7 by

(a) extending its term by one year to October 31, 1993,

(b) increasing the amount of gas that may be removed in a 24-hour period by 545 million cubic feet to 2715 million cubic feet,

(c) increasing the quantity of gas that may be removed annually by 140 billion cubic feet to 860 billion cubic feet,

(d) increasing the volume of gas that may be removed during the term of the permit by 2.1 trillion cubic feet to 19.2 trillion cubic feet,

(e) adding to the list of fields, pools, and areas from which gas may be removed from the Province the following: Amisk, Armada, Bassano, Big Bend, Black Diamond, Burnt Timber, Castor, Chestermere, Craig Lake, Ferrier, Hughenden, Hunter Valley, Jumping Pound West, Kirkpatrick, Lake Newell, McMullen, Mitsue, Pelican, Quirk Creek, Sedgewick, Travers, Turin, West Long Coulee, Whitecourt and Wildhorse Creek.

The Duhamel Field was also included in its application. At the hearing Trans-Canada stated that the producer in the Field is not able to deliver gas. The applicant, therefore, asked that the field not be included in the list applied for.

Trans-Canada tendered a letter in which The Alberta Gas Trunk Line Company Limited stated that it is prepared to construct the facilities necessary to transport the additional volumes requested.

Reserves

Trans-Canada estimated the initial marketable reserves in the fields now in its permit and in the new areas applied for to be some 23.7 trillion cubic feet, consisting of 21.3 trillion in the fields now in the permit and 2.4 trillion in the new areas. This is some 4.5 trillion more than the volume applied for. Of the total, the applicant considered some 21.9 trillion cubic feet to be proved reserves.

In assessing total Provincial reserves Trans-Canada did not make individual estimates of the reserves in each field or area of the Province containing gas. It did, however, make estimates for those areas in which significant development had occurred since the Board's last estimate or where it submitted the Board's estimate was too low. In this manner, the applicant estimated that at March 31, 1968, the remaining established reserves of the Province were 41.3 trillion cubic feet, or the equivalent of 43.9 trillion cubic feet of 1000 Btu gas. The 41.3 trillion cubic feet results from adding to the Board's December 31, 1967, estimate of 39.7 trillion cubic feet 1.5 trillion cubic feet as the increase in reserves in the fields under contract to the applicant, 0.4 trillion cubic feet as the increase in certain other fields in the Province, and by subtracting 0.3 trillion cubic feet of gas that had been produced since December 31, 1967.

A detailed discussion of Trans-Canada's estimates and comparative estimates of the Board is presented in Appendix A.

Reserves under contract

Trans-Canada submitted that it had under contract some 19.6 trillion cubic feet of the 23.7 trillion cubic feet it estimated were not committed to others in the fields now in its permit and in the areas named in its application. It stated that in the fields now in the permit some 83 per cent of the gas is under contract to it. The applicant stated that in the new fields 2.0 trillion cubic feet, or some 95 per cent of the reserves, are under contract, and that a significant portion of the reserves in each of such areas requested is under contract to it.

Trans-Canada indicated at the hearing that it no longer had contracts to purchase gas in the Abee, Baptiste, Calling Lake, Francis, Thorhild, Fenn-Big Valley, Minnehik-Buck Lake and Stettler Fields. Its views with respect to the retention of the fields in its permit are presented in Section IV.

Nine of the new areas applied for, Amisk, Castor, Craig Lake, Hughenden, Jumping Pound West, Kirkpatrick, Lake Newell, McMullen, and Pelican, are subject to development contracts, which require that producers prove up a specified minimum reserve before Trans-Canada is obligated to purchase the gas. Trans-Canada will, however, purchase gas in the areas if it causes a large diameter pipe line to be constructed into the areas prior to the minimum reserve being developed.

Trans-Canada has renegotiated many of its gas purchase contracts with respect to the daily volumes of gas which it may purchase. The old contracts called for a delivery rate of about one million cubic feet per day for each 10 billion cubic feet of reserves. The daily rate in the new contracts is one million cubic feet for each 8.5 billion cubic feet of reserves. The new fields are subject to the accelerated withdrawal rates. Trans-Canada said that the increased rates of withdrawal resemble more closely its marketing pattern.

Deliverability

Trans-Canada submitted a detailed deliverability study showing that the entire 19.2 trillion cubic feet of gas applied for could be produced during the term of the permit, if extended in accordance with the application, from the fields in the permit and from the new areas applied for. Some 17.8 trillion cubic feet of the total would come from fields now in the permit with the remaining 1.4 trillion cubic feet to come from the new areas.

Trend in Growth of Reserves

The applicant submitted that the long term growth of initial marketable reserves of gas in Alberta has been at the rate of 2.6 trillion cubic feet per year. The rate during the previous two years was equivalent to the long term annual rate of 2.6 trillion cubic feet.

Surplus

Trans-Canada estimated that, using the method of calculation outlined in recent Board reports, an overall surplus of 4.4 trillion cubic feet of 1000 Btu gas existed in the Province at March 31, 1968.

The applicant obtained the estimate by updating the calculation presented by the Board in OGCB Report 67-C(1).

Trans-Canada considered that there was a contractable surplus of 3.4 trillion cubic feet and a future surplus of 1.0 trillion cubic feet, assuming that two years growth of gas reserves at the long term rate of 2.6 trillion cubic feet per year would be used to meet the future or remaining requirements of the Province.

The applicant argued, therefore, that more than a sufficient surplus exists to meet the additional volume applied for of 2.1 trillion cubic feet.

Details of Trans-Canada's calculations appear in Appendix D.

---

(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. October 1967.

III SUBMISSIONS OF INTERVENERS

The Alberta Division of the Canadian Petroleum Association

The submission of CPA supported the application of Trans-Canada and also recommended revised criteria for determining the existence of a removable surplus of gas in the Province.

CPA reiterated the position it took at the June, 1967, hearing with respect to the use of probable reserves as it defined them, and the use of five years growth of gas reserves in the calculation of the contractable and the future surplus. In addition, CPA proposed that the period of protection be reduced from 30 years to 25 years.

A detailed discussion of CPA's views is presented in Section IV of this report.

Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited

The Utility Companies did not object to the granting of the application if the Board should find, by using the method of surplus assessment set out in Board Report OGCB 67-C, that there are sufficient volumes of established reserves surplus to the needs of the Province.

The interveners adjusted their estimate of the 30-year requirements of Alberta, submitted in June, 1967, to apply to the new period 1968 to 1997. The Utility Companies' estimate was that 12.8 trillion cubic feet will be required for delivery during the 30-year period. The estimate does not include fuel requirements for compressors on trunk lines and shrinkage in the volumes of gas being carried by trunk lines due to extraction of liquids. The estimate includes most but not all of the new requirements for iron ore processing submitted by Peace River Mining.

The Utility Companies opposed CPA's proposal to reduce the period of protection to 25 years. They also expressed a conditional objection to the increased use of gas reserve growth in meeting the requirements of Alberta.

A more detailed discussion of the views of the Utility Companies with respect to the CPA submission is presented in Section IV.

Chevron Standard Limited

Chevron supported the inclusion of the Mitsue Field in the list of fields and areas applied for by Trans-Canada. A forecast of the availability of gas from the field was submitted by Chevron at a hearing held earlier to consider an enhanced recovery scheme in the field.

Imperial Oil Enterprises Ltd.

Imperial advocated the granting of Trans-Canada's application and presented an estimate of the reserves in the Quirk Creek area. Imperial considered that of its estimate of 490 billion cubic feet, 75 per cent was proved reserve of marketable gas. It considered the remaining 120 billion cubic feet as a probable reserve.

Independent Petroleum Association of Canada

IPAC urged the Board to approve the application. It contended that even with the conservative approach used by the Board in determining the existence of a surplus, sufficient gas over and above that needed to meet Alberta's requirements and present commitments now exists in the Province. A further discussion of IPAC's views is presented in Section IV.

Pan American Petroleum Corporation

Pan American submitted revised estimates of the reserves of gas in the Marten Hills Field. It considered that the Wabiskaw formation contains 884 billion cubic feet of marketable gas, 818 billion cubic feet of which it called proved. The Wabamun formation estimate consisted of 353 billion cubic feet of proved gas and 10 billion cubic feet of probable gas for a total reserve of 363 billion cubic feet. The Pelican and Grand Rapids formations were considered by Pan American to contain 13 billion cubic feet of gas, all of which it called proved.

The total reserves of marketable gas in the Marten Hills Field were estimated by Pan American to be 1260 billion cubic feet consisting of 1184 billion cubic feet of proved gas and 76 billion cubic feet of probable gas.

Pacific Petroleums Ltd.

Pacific supported the inclusion of the Whitecourt area in the list of new areas from which Trans-Canada be authorized to remove gas. It submitted that the marketable reserves under lands in which it has an interest are some 298 billion cubic feet. Pacific considered that of its estimate 282 billion cubic feet are proved reserves.

Peace River Mining & Smelting Ltd.

Peace River Mining is engaged in developing a new patented process to produce iron powder from iron ore deposits the company has under lease in the Peace River region.

In its submission Peace River Mining stated that a pilot plant located at the Alberta Research Council facilities was completed in 1966. After preliminary tests it became evident that the technological feasibility of an extraction plant in the Peace River area with a minimum capacity of 100,000 tons per year was contingent upon the proven operation of a smaller scale commerical plant. Accordingly a decision was made to build a commercial plant using the same process but a different raw material (scrap iron). The plant to be located in Southern Ontario will be of intermediate size and will consume some 50,000 tons of scrap iron per year. Construction of the plant has commenced with completion scheduled for early in 1970.

With respect to markets and gas requirements, Peace River Mining expressed a belief that despite a pause in the growth of iron powder markets last year, a rate of growth of 25 per cent per year is reasonable and that the projections of production and associated gas consumption made in the company's 1966 submission to the Board are essentially correct. Thus Peace River Mining indicated a production schedule for the Peace River plant of 100,000 tons per year initially in 1973, growing to an average of 1,500,000 tons per year over the period 1981 to 1990 and averaging 2,500,000 tons per year 1991 to 2000. The attendant gas requirements totalled some

2,437 billion cubic feet over the period 1973 to 2000. The intervener emphasized that the economic recovery of iron by its process at a plant in the Peace River area would be dependent on the availability of an adequate supply of gas at the lowest possible cost.

During the hearing Dr. C. P. Gravenor, the witness for Peace River Mining, stated that if the Ontario plant were successful, the Peace River plant may be completed by the end of 1973. The witness also stated that the decision to develop the Peace River deposits was dependent also on the fruition of continuing tests on the Peace River ore itself.

Subsequent to the hearing Peace River Mining submitted a letter to the Board which was circulated to the applicant and interveners. The letter stated that the construction and successful operation of the Ontario plant would not eliminate the necessity for a further total feasibility study on the Alberta plant. Such a study would entail consideration of the costs of converting iron powders to steel strip.

IV MATTERS OF SPECIAL CONCERN

There were a number of issues raised at the hearing involving present Board policy that the Board believes it must consider. One of the issues involves the proposed use of probable reserves as defined by CPA rather than established reserves in the estimation of contractable reserves. The second issue concerns the proposed reduction in the period of protection from 30 years to 25 years. The third issue involves CPA's proposal that additional growth of gas reserves be used in calculating the gas surplus to Alberta's requirements and commitments. Another issue involves the applicant's proposal to increase the proportion of the gas reserves withdrawn in any day or year. The final issue concerns the inclusion of fields or areas in the permit in which the Permittee does not have contracts for the purchase of gas.

Probable Reserves

(1) Views of CPA

CPA urged the Board to use probable reserves, which it defined as "proved reserves plus a realistic estimate of the additional reserves that will ultimately be recovered from known reserves", in calculating the volumes of gas surplus to the contractable requirements and commitments. Also, it maintained that probable reserves should be used in assessing the trends in growth of gas reserves.

CPA argued that reserves now established will certainly grow with further drilling and the Board should, therefore, recognize some of this growth in calculating the contractable surplus.

(2) Views of the Board

The reasons advanced by CPA for the use of probable reserves are almost identical to those presented at the last hearing held in June, 1967. The Board in its report on that hearing, OGCB report 67-C(1), at pages 20 and 21 rejected CPA's suggestion for the reasons cited in the report. There were no new arguments tendered and nothing has transpired in the meantime to suggest to the Board that a change in its previous position is desirable. The Board, therefore, again rejects CPA's proposal regarding probable reserves and will continue to assess the trends in growth of reserves and the contractable surplus using established reserves.

Period of Protection

(1) Views of CPA

CPA proposed that the Board reduce the contractable Alberta requirements from the greater of 30 times the current year's consumption or the sum of the reserves now connected to supply Alberta's requirements to the greater of 25 times such consumption or the sum of the reserves so connected. Also, it proposed that the 30-year period for the protection of Alberta's requirements be reduced to 25 years.

CPA stated that the life index for gas in Alberta is 38.5 years compared with the United States index of 15.9 years, and contended that this reflected an excessive and unncessary degree of protection for Alberta requirements.

---

(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. October 1967.

CPA argued that the present 30-year period of protection of Alberta requirements is excessive and urged the Board to adopt a 25-year period as being more appropriate. It suggested that industry generally operates on 25-year contracts and that "it has been found by practice that this is ample to protect requirements". The intervener submitted that the amount of gas dedicated to protect fully the 30-year requirements of Alberta is equivalent to 79 years of supply at the 1968 rate of consumption in the Province.

CPA recognized that, regardless of the period of protection, gas may be held back in the future to meet Alberta requirements. It argued, however, that this is not the time to "lock-in" reserves when only 45 to 50 per cent of the ultimate reserves of Alberta have been discovered. CPA urged the Board to view the protection of requirements in a broad context and to recognize industry incentive as an important ingredient of real protection. CPA was concerned that an overly protective policy could result in a decline in incentives to the ultimate detriment of both the people of Alberta and the gas producer. CPA argued that the agreements between the Utility Companies and the companies removing gas from the Province give the Utility Companies prior rights to the gas being removed, if any of it were required for Alberta requirements.

(2) Views of Other Interveners and the Applicant

Alberta's two major cities, Calgary and Edmonton, opposed CPA's proposal. They argued that they had not had sufficient time between the filing of CPA's intervention and the hearing to prepare a rebuttal. Also, they contended that a hearing of an application to remove gas is not the proper forum to reconsider the period of protection, but that it should be the subject of a special hearing.

The Utility Companies also opposed the proposal, arguing that a reduction in the period of protection would not result in more contractable surplus being available for removal from the Province. They contended that there are now sufficient incentives for the industry to explore for gas and that a relaxation of Board policy for this purpose is unnecessary.

The applicant did not take a position with respect to this matter.

(3) Views of the Board

The Board adopted the 30-year period in 1951(2), and it has since become accepted not only as Board policy but as the policy of the Government. The period may be arbitrary but no more so than the 25-year period proposed by CPA, and the Board considers it proper that the period of protection for the Province exceed the normal contracting period for industry.

The Board considers CPA's comparisons of life indices totally irrelevant to the question of the proper protection of Alberta's future requirements. The life index of 38.5 years referred to by CPA is merely the ratio of CPA's estimate of proved remaining reserves (well over half of which are committeed to removal from the Province) to the current total production and has little to do with the protection of Alberta's future requirements. The 79-year index is the ratio of the Province's 30-year requirements, including the reserves needed for protection of the thirtieth year peak, to its current annual requirements. This in no way reflects the actual reserves dedicated or set aside for the Province's protection. So long as there is no serious deficiency in the future category the ratio which properly measures the reserves held back for Provincial protection is the ratio of the contractable requirements (for which gas is held back, but mostly under contract arrangements) to the current requirements, and this is 30 years. The remaining protection is provided through

---

(2) Interim report with respect to applications now before the Board for permission to remove gas or cause it to be removed from the Province under the provisions of The Gas Resources Preservation Act. January 1951.

(a) gas whose production is deferred for reasons of oil or natural gas liquids conservation,

(b) gas presently beyond economic reach which will become accessible in the future, and

(c) the growth in gas reserves forecast over the next two years.

If there were a significant future deficiency additional gas would have to be held back and this would increase the 30-year figure but it is hardly conceivable that the figure would approach 79 years.

The foregoing relates to the period of years for which protection should be provided. The Board also has reconsidered the related matter of the period of years upon which the contractable requirements should be based. Its views with respect to this are similar. Furthermore, the reserves actually under contract or otherwise committed have in the past slightly exceeded and now are only slightly less than 30 times the current annual requirement. In the Board's view this confirms that the use of the 30 times figure is not excessive.

The Board agrees with the Cities and the Utility Companies that if a matter of such importance as the period of years for which the future requirements of the people of the Province should be protected were to be subject to reconsideration it should only be after generous notice to all interested parties.

This matter, however, is not one that the Board is prepared to consider further.

Growth of Reserves

(1) Views of CPA

CPA again called on the Board to consider increasing to five the number of years of growth of gas reserves used in calculating the gas surplus to the requirements and commitments. CPA reaffirmed the position it took in 1967, being that

(a) there is now sufficient history to provide convincing evidence as to the ability of the gas industry to meet the requirements of Alberta,

(b) the trends in the rate of growth are such as to suggest that reserves will continue to increase for many years and that exploration will not come to a sudden halt in two years, and

(c) the use of only two years growth may result in some contractable reserves being set aside for a use that would not materialize until late in the 30-year period.

CPA was concerned "that on the basis of the Board's present policy and having regard to the increase through time of the volume of gas required for peak day protection in the thirtieth year, a situation will inevitably develop where an existing surplus of contractable gas over and above the contractable requirements of Alberta will have to be withheld from export markets because of lack of a future surplus". CPA argued that since only about half of the ultimate reserves of Alberta have been discovered it is far too soon to "lock-in" reserves that will not be needed for many years. It advocated that such an undesirable occurrence could be averted by using five years growth of gas reserves. CPA urged the Board to express its willingness to use five years growth now rather than wait until a change is needed in order to release a contractable surplus. A change now would be "free from those pressures which might otherwise cause a change in policy to be unjustifiably regarded as expediency".

(2) Views of Other Interveners and the Applicant

The Cities of Edmonton and Calgary opposed the proposal and took the same general position as they did in the matter of the period of protection.

The Utility Companies indicated their qualified objection to the proposal. If a future application for removal of gas could not be granted because some of the contractable surplus would be needed to meet future requirements, the Utility Companies would then wish to examine the circumstances with respect to the number of years of growth to be used in calculating the surplus.

IPAC supported CPA's suggestion. Mr. Lee for IPAC testified that if the Board could show a large future surplus it would be less of an "irritant to the public" than the essentially balanced position now being shown. He said that the future surplus should not be shown as zero because future exploratory effort will certainly result in much more additional gas being developed. The indication of a zero future surplus is, he said, misleading. The use of five years growth of reserves would overcome these objections.

The applicant did not take a position with respect to the additional years of growth that should be used in assessing the surplus available for removal.

(3) Views of the Board

The contention of CPA that greater reliance be placed on the growth of gas reserves was considered by the Board in its last Trans-Canada decision in OGCB Report 67-C. At that time the Board reconfirmed its earlier decision that under certain conditions it would be prepared to rely upon more than two years growth of gas reserves for the protection of the thirtieth year peak requirements. Such greater reliance would depend "upon the long term growth rate of gas reserves, the number of years of growth that would be needed to satisfy the portion of the cushion gas for requirements not otherwise met, the percentage of the apparent ultimate reserves of the Province that have already been developed, and the likelihood that the peak day requirements would to some extent be supplied by other means, such as more drilling and more use of storage and compression".

The Board has not given further detailed consideration to either the CPA argument or the Board's previous conclusion. It recognizes that substantial gas reserves remain to be discovered in the Province and that there is no evidence to suggest that the current long term trend in growth of gas reserves will not continue for several years. On the other hand the Board recognizes that the CPA proposal if adopted would constitute a significant change in Board policy. The Board agrees with the

Cities that a matter of this importance should only be considered after all parties have had adequate opportunity to express their views. Consequently, the Board is prepared to reconsider this matter at a special hearing if CPA or any other interested party wishes to make such an application.

In the meantime the Board will continue to use the method outlined in previous reports for determining the Alberta surplus.

Daily and Annual Withdrawals

(1) Views of the Applicant

Trans-Canada's contracts in the new fields call for a daily delivery of one million cubic feet for each 8.5 billion cubic feet of marketable reserves. This represents an increased withdrawal rate from previous contracts which were based on a 1:10 ratio. Many of the contracts in fields and areas now in the permit have been renegotiated to provide for the delivery of gas on the new basis. Trans-Canada said that the increased rate would provide it with the flexibility needed to meet its market demand.

(2) Views of Interveners

None of the interveners offered evidence or argument on this point.

(3) Views of the Board

Deliveries under the new and renegotiated contracts will result in faster depletion of the fields and pools included in the permit. This will have the effect of reducing the number of years during which the maximum daily and annual volumes specified in the permit can be met from the fields and areas included in the permit.

Since the maximum rate at which a well may produce gas is governed by The Oil and Gas Conservation Regulations, the Board sees no reason why the accelerated production rate should not be approved.

Fields not Subject to Contract

The Abee, Baptiste, Calling Lake, Francis and Thorhild Fields have been named in the applicant's permit since an amendment to Permit No. TC 64-6 in the summer of 1966. At that time Trans-Canada had development contracts with producers in the fields which since have lapsed.

Gas from the Fenn-Big Valley and Stettler Fields in which Trans-Canada has no contracts is processed in the same plant as gas from the Nevis field. The Fenn-Big Valley and Stettler portions of the gas go to local utilities and the Nevis portion to Trans-Canada.

Minnehik-Buck Lake is also named in Trans-Canada's permit although the permittee does not have contracts with producers in that field.

(1) Views of Trans-Canada

The Abee, Baptiste, Calling Lake, Francis and Thorhild Fields are in the vicinity of the proposed pipe line from Marten Hills. Trans-Canada said these fields were at distances from the proposed line varying from about 13 to 33 miles and had developed reserves varying from about 7 to 50 billion cubic feet. It submitted that the fields should remain in the permit as the construction of the pipe line may encourage the producers in the fields to develop reserves which would justify contracts with Trans-Canada.

With regard to Fenn-Big Valley and Stettler, Trans-Canada stated that gas from these fields would commingle with Nevis gas in the processing plant and consequently inclusion of the fields in the permit was technically justified.

Trans-Canada said it had no present plans for contracting for Minnehik-Buck Lake gas and could offer no reason for retention of this field in the permit.

(2) Views of the Board

The Board believes that, in absence of contracts and on the basis only of the hope that reserves would be developed more rapidly than they did during the terms of the development contracts, the inclusion of the Abee, Baptiste, Calling Lake, Francis and Thorhild Fields in the permit is not justified.

With regard to Fenn-Big Valley and Stettler, the Board believes these fields should be dropped from the permit and that the dropping of them will not create a problem as long as the volumes of gas moving from the plant to Trans-Canada do not exceed the volumes of gas delivered to the plant from the Nevis Field.

V FINDINGS

The Board having heard publicly the application under The Gas Resources Preservation Act, 1956, of Trans-Canada Pipe Lines Limited, and having studied the evidence submitted by the applicant and the interveners at the public hearing, and having regard to the advice of its staff and to its own knowledge, finds as follows:

1. IN THE MATTER OF THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the established reserves of marketable gas remaining in the Province of Alberta at May 31, 1968, to be some 41.5 trillion cubic feet, or the equivalent of 43.6 trillion cubic feet of 1,000 Btu gas.

Of the latter total, some 2.9 trillion cubic feet are now considered to be beyond economic reach and some 6.0 trillion cubic feet will have production deferred, leaving a contractable reserve of 34.7 trillion cubic feet of 1,000 Btu gas.

The present estimate of 43.6 trillion cubic feet is some 1.4 trillion cubic feet more than the Board's estimate at December 31, 1967. The increase is largely due to additional drilling in the Kaybob South, Marten Hills, and Quirk Creek fields.

Details of the Board's estimates and a discussion of the more significant changes are presented in Appendix A.

2. IN THE MATTER OF THE TRENDS IN THE GROWTH OF RESERVES OF GAS IN ALBERTA

The growth in initial marketable reserves of gas over the past 17 years due to new discoveries and to appreciation of previous discoveries has been at the average rate of some 2.5 trillion cubic feet per year. Since the Board did not make an estimate of reserves at May 31, 1966, a precise figure for the growth of gas reserves during the immediately preceding two-year period, June 1, 1966, to May 31, 1968, is not available. However, during the 27-month period, March 1, 1966, to May 31, 1968, reserves increased by 5.8 trillion cubic feet - equivalent to 2.6 trillion cubic feet per year.

In keeping with the Board's policy of using the lesser of the reserves equivalent to those that would be developed in a two-year period at the long term growth rate, or at the rate experienced during the immediately preceding two-year period, the additional reserves to assist in meeting the future requirements of Alberta amount to 5.0 trillion cubic feet.

3. IN THE MATTER OF THE PRESENT AND FUTURE REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS

The Board estimates Alberta's requirements for the 30 years, June 1, 1968, to May 31, 1998, to be 14.5 trillion cubic feet of 1,000 Btu gas, with a peak day requirement in the thirtieth year of 3.4 billion cubic feet. The present estimate represents an increase of 2.1 trillion cubic feet in the total 30-year requirements since the Board's last estimate, which was for the period, June 1, 1967, to May 31, 1997.

The commitments remaining at May 31, 1967, associated with permits issued for the removal of gas from Alberta, total some

24.5 trillion cubic feet of 1,000 Btu gas.

Details of the Board's estimates of Alberta's requirements and permit commitments are presented in Appendix C.

4. IN THE MATTER OF THE MEETING OF ALBERTA'S 30-YEAR REQUIREMENTS AND PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

The Board estimates that reserves totalling some 19.5 trillion cubic feet of 1,000 Btu gas are necessary to meet the annual and peak day requirements of Alberta for the 30-year period, June 1, 1968 to May 31, 1998. Of this total about 14.5 trillion cubic feet are required for actual deliveries with the remaining 5.0 trillion cubic feet needed to meet the thirtieth year peak day.

The Board's estimate of 19.5 trillion cubic feet may also be considered to consist of 7.4 trillion cubic feet of contractable requirements and 12.1 trillion cubic feet of remaining requirements, the latter being a measure of the amount of reserves needed from sources not now under contract or connected to the Alberta market.

The Board estimates that 25.0 trillion cubic feet of 1,000 Btu gas are required to meet the present permit commitments, of which some 0.5 trillion cubic feet represent the reserves required to ensure deliverability in the terminal year for those permits under which it is contemplated that substantial daily withdrawals for which protection has historically been provided will continue to the end of the term.

When the contractable requirement, 7.4 trillion cubic feet, and the gas needed to satisfy the permit commitments, 25.0 trillion cubic feet, are deducted from the contractable reserve of 34.7 trillion cubic feet, a contractable surplus of 2.3 trillion cubic feet results.

The remaining and future reserves, totalling some 12.5 trillion cubic feet, consist of 5.3 trillion cubic feet of deferred gas which will be available within the 30-year period, 2.2 trillion cubic feet of gas now beyond economic reach but which the Board believes will be within economic reach within 30 years, and 5.0 trillion cubic feet representing two years growth of gas reserves at the long term average rate. Comparing the total with the 12.1 trillion cubic feet of remaining Alberta requirements indicates a surplus of 0.4 trillion cubic feet in this future category. This results after full provision for the 3.2 trillion cubic feet required from sources not now connected to meet Alberta's thirtieth year peak day.

The overall surplus before release of reserves required to protect peak day in permits is 2.7 trillion cubic feet. The cushion gas released after the expiration of the subsisting permits will increase the overall surplus to 3.2 trillion cubic feet.

Details of the Board's analysis of these matters appear in Appendix D.

5. IN THE MATTER OF THE VOLUMES UNDER CONTRACT AND THE PERMIT VOLUMES APPLIED FOR

The Board is satisfied that Trans-Canada has under contract in excess of 80 per cent of the established reserves, as estimated by the Board, within the fields, pools, and areas which the applicant applied to have added to its permit. Furthermore, the applicant has under contract a sufficient portion of the reserves in each field or area to warrant its inclusion in the permit.

The Amisk, Castor, Craig Lake, Hughenden, Jumping Pound West, Kirkpatrick, Lake Newell, McMullen, and Pelican fields, being under development contracts discussed in OGCB Report 67-C(1), should be included in the permit subject to a condition requiring Trans-Canada to satisfy the Board within three years that the gas will be effectively removed from the Province pursuant to the permit.

The Board finds that Trans-Canada does not have contracts for the purchase of gas in the Abee, Baptiste, Calling Lake, Francis, Thorhild, Fenn-Big Valley, Minnehik-Buck Lake and Stettler Fields. For the reasons given in Section IV, these fields should be removed from the permit. The reserves in the fields, some 77 billion cubic feet, should be deducted from the volumes which may be removed under the permit.

6. IN THE MATTER OF THE APPLICATION FOR REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE APPLICATION WERE GRANTED

The additional volume applied for by Trans-Canada, 2.2 trillion cubic feet, consists of 0.3 trillion cubic feet from fields, pools, and areas included in its present permit and 1.9 trillion from new fields. The Board disagrees with Trans-Canada's estimate of reserves in some of the new fields and some of the fields now in its permit. However, the Board finds that its estimate of the reserves in both groups of fields totals some 0.6 trillion cubic feet greater than the volume applied for.

---

(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. October 1967.

If the removal of the additional volumes applied for by Trans-Canada is authorized, the reserves needed to meet the commitment of all permits would increase from the present 25.0 trillion cubic feet of 1,000 Btu gas, of which 0.5 trillion cubic feet is for the protection of deliveries at the maximum daily rate authorized and anticipated in certain of the permits, to 27.2 trillion cubic feet. The contractable surplus would be reduced from 2.3 trillion cubic feet to 0.1 trillion cubic feet. The future surplus of 0.4 trillion cubic feet would remain unchanged. The overall surplus would, therefore, be 0.5 trillion cubic feet before the release of reserves required to protect peak day in certain permits.

The release of the cushion gas after the expiration of the permits would result in an overall surplus of 1.0 trillion cubic feet.

Accordingly, the Board finds that the additional volumes of gas applied for are surplus to the requirements of the Province and the present permit commitments. The Board is satisfied that the gas may be produced within a 25-year term - although the Board estimates that the reserves would not, in each case, support deliveries at the maximum daily rates requested during the last several years of the term.

Details of the Board's analyses relating to these matters are presented in Appendix E.

7. IN THE MATTER OF THE OTHER AMENDMENTS APPLIED FOR BY TRANS-CANADA PIPE LINES LIMITED

(1) The application for an extension in the term of its permit

The Board agrees with the applicant that the addition to reserves, the deliverability characteristics of the fields, and the contracts which Trans-Canada has entered into make a one-year extension of the term of the permit desirable.

(2) The increase in the daily and annual withdrawal rates

The Board believes that the increased rates of production will not be detrimental to the consumers of Alberta or to the ultimate recovery of gas. It, therefore, does not object to Trans-Canada's practice of contracting for gas on the basis of one million cubic feet per day for each 8.5 billion cubic feet of reserves.

8. IN THE MATTER OF THE DISPOSITION OF THE APPLICATION OF TRANS-CANADA PIPE LINES LIMITED

In the light of its findings and its responsibility under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to amend Permit No. TC 67-7 by increasing the volume of gas which Trans-Canada may remove from the Province by 2.1 trillion cubic feet, by adding the 26 new fields and areas applied for, by deleting the eight fields in which the applicant does not have contracts and by extending its term to October 31, 1993; the permit and the amendments to be consolidated in the form shown in Appendix F and subject to the terms and conditions therein contained.

Respectfully submitted

G. W. Govier, P.Eng.
Chairman

A. F. Manyluk, P.Eng.
Deputy Chairman

Vernon Millard
Board Member

Dated at Calgary, Alberta
this 1st day of November, A.D. 1968.

APPENDIX A

THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the remaining established reserves of marketable gas in Alberta at May 31, 1968, were 41.5 trillion cubic feet, or the equivalent of 43.6 trillion cubic feet of 1,000 Btu gas. This estimate represents an increase on an actual heating value basis of some 1.8 trillion cubic feet since December 31, 1967, when the Board's estimate was 39.7 trillion cubic feet. On an actual heating value basis, Trans-Canada estimated that the remaining established reserves at March 31, 1968, were 41.3 trillion cubic feet. Trans-Canada submitted revised reserve estimates for several fields where it has contracted reserves, and for certain other fields where significant increases had occurred since the year end. For the remainder of the pools in the Province the applicant accepted the estimates of the Board as estimated at December 31, 1967, and published in OGCB Report 68-18.

While only the established reserves are discussed in this report, the Board has calculated proved and probable reserves of gas. The definitions and interrelationships of these categories of reserves are as follows:

Proved Reserves are the recoverable gas reserves within the area of a pool completely delineated by drilled wells. A portion of such reserves may be in undrilled drilling spacing units but so located structurally that there is every reasonable probability that the reserves will be produced by wells drilled, or to be drilled in nearby drilling spacing units.

Probable Reserves are the reserves of gas estimated to be recoverable from the pool beyond the proved limits of the pool. The probable pool limits are based on normal geological expectation.

Established Reserves are the reserves of gas whose existence and estimated amount can reasonably be counted upon. They include all of the proved reserves and a judgment portion (usually 50 per cent) of the probable reserves.

In its estimate of reserves, the Board has had regard for the estimates presented by the applicant and interveners at the hearing, the estimates included in various submissions presented recently to the Board, and evaluations made by its staff. The staff has reviewed all estimates submitted by the applicant and the interveners as well as its own previous estimates where production history, additional drilling or other newly acquired information has become available.

The majority of the increases in the Board's estimates of remaining marketable reserves in the five-month period ending May 31, 1968, were the result of successful development drilling in various pools, whereas the majority of the reductions were due to the production of gas for marketing during the same period or the result of unsuccessful development drilling.

A comparison of the Board's reserve estimates for the year ending December 31, 1967 and at May 31, 1968, follows:

	Actual Basis	1,000 Btu Basis
	(Trillions of	Cubic Feet)
Remaining Established reserves of Marketable gas at December 31, 1967	39.7	42.2
Net Additions to Reserves	2.3	1.9
Marketable Gas Produced	0.5	0.5
Remaining Established Reserves of Marketable Gas at May 31, 1968	41.5	43.6

The Board staff has recently reviewed the heating values of gas from producing fields in co-operation with the principal utilities and the permit holders in the Province. The heating values previously utilized were largely based on the results of analyses of samples taken prior to the commencement of normal production from the pools. This review resulted in both upward and downward amendments in heating values and hence corresponding adjustments in reserves of gas on a 1000 Btu basis. The net result however, was a reduction of 0.4 trillion cubic feet in reserves on a 1000 Btu basis.

The following tabulation lists some of the larger pools or strata for which there have been significant changes in the Board's estimates of initial marketable reserves (unadjusted for heating value) or for which there are significant differences between the Board's estimate and the reserve estimates of other interested parties:

	Board's Estimate as of		Other Estimates as of May 31, 1968	
Field or Area Pool or Stratum	Dec.31 1967	May 31 1968	Estimators	Estimates
Crossfield East Wabamun A	660	660	Trans-Canada	761

Field or Area Pool or Stratum	Board's Estimate as of Dec. 31 1967	 May 31 1968	Other Estimates as of May 31, 1968 Estimators	 Estimates
Ferrier Cardium E	300	250	Trans-Canada	281
Gilby Rundle C	170	210	None	None
Jumping Pound West Rundle A	560	530	None	None
Jumping Pound West Rundle B	140	170	None	None
Kaybob South Beaverhill Lake A	370	700	None	None
Kaybob South Beaverhill Lake B	Nil	700	None	None
Marten Hills Wabiskaw A	400	550	Trans-Canada Pan American	577 885
Marten Hills Wabamun A	270	270	Trans-Canada Pan American	236 363
Provost Viking A & B	800	800	Trans-Canada	990
Quirk Creek Rundle A	98	450	Trans-Canada Imperial	489 490

Crossfield Wabamun A Pool: The Board's initial marketable reserve estimate of 660 Bcf for the Crossfield Wabamun A Pool has not changed since the year-end. The Board does not include any reserves in the probable category for this pool whereas Trans-Canada has estimated that some 50 Bcf of probable reserves exist. In addition a difference in porosity and permeability cut-offs results in a lesser pore volume estimate by the Board.

Ferrier Cardium E Pool: Reserve estimates for this pool have decreased from 300 Bcf at the year-end to 250 Bcf as of May 31, 1968. This is due primarily to a geological re-interpretation of the pool and an increase in the expected reservoir loss. Trans-Canada has estimated some 281 Bcf with the difference in estimates being due to a difference in rock volume estimates.

Gilby Rundle C Pool: A review of this pool's performance and a complete re-examination of the engineering factors has resulted in an increase of 40 Bcf in the reserve estimate. There were no reserve estimates submitted for this pool by other parties.

Jumping Pound West Rundle A and B Pools: One new well and a re-evaluation of the geological and engineering factors has altered the reserve estimates for the Jumping Pound West Rundle A and B Pools. The A pool reserve estimate has decreased by 30 Bcf to 530 Bcf, and the B pool estimate has increased 30 Bcf to 170 Bcf. There were no reserve estimates submitted for these pools by other parties.

Kaybob South Beaverhill Lake A Pool: This reserve estimate has increased 330 Bcf since the last evaluation at the year-end. The Board now estimates the initial marketable reserves in this pool to be 700 Bcf as of May 31, 1968. The greater part of this increase is due to the increase in reservoir volume indicated by several new wells that have been drilled during the interim period.

Kaybob South Beaverhill Lake B Pool: Similarly, new drilling has been responsible for the development of this pool where the Board currently estimates the initial marketable reserves at 700 Bcf. There were no submissions from other parties available for a comparison of reserves in this pool.

Marten Hills Wabiskaw A Pool: The Board's estimate of reserves for this pool has increased to 500 Bcf as of May 31, 1968. This is essentially in agreement with the Trans-Canada estimate but considerably less than the estimate submitted by Pan American. In this pool Pan American has estimated a larger pore volume and a higher recovery than the Board which accounts for most of the difference between the estimates.

Marten Hills Wabamun A Pool: The reserves estimate for the Marten Hills Wabamun A Pool remained at 270 Bcf for the period ending May 31, 1968. This estimate also is in substantial agreement with the estimate of Trans-Canada, but considerably less than the estimate of Pan American. The pore volume calculations of Pan American are larger than those of either the Board or Trans-Canada.

Provost Viking A and B Pools: The aggregate reserve estimate for these pools has remained at 800 Bcf. Trans-Canada submitted a material balance calculation for a major portion of the total reserve which results in a higher estimate than the volumetric calculations of the Board. The material balance submitted was based on production and pressure data for only one year. Because of this the Board has requested additional data for the pool and will review its estimate again when the additional data is available.

Quirk Creek Rundle A Pool: This newly discovered pool has reserves estimated by the Board to be 450 Bcf as of May 31, 1968. This estimate is only slightly less than the estimates of Trans-Canada and Imperial Oil. The minor difference is due to a difference in the estimates of areal extent.

Some of the reserves for pools in the north-west part of the Province (Rainbow - Zama area) are listed in the body of Table A-1. Because much of the data is still confidential the remainder of the reserves in this area are included in the entry "confidential pools" at the end of the table.

The Board's estimates of established reserves of gas tabulated by fields and areas are presented in Table A-1. Within each field or area, pools designated by Board orders and having initial marketable reserves of 10 billion cubic feet or greater are shown separately. The reserves of the remaining pools in a field or area are grouped by formation. The table does not show separately fields or areas where the Board's estimate of initial marketable reserves is less than 10 billion cubic feet unless the reserve is supplying a market. In addition, the table does not show reserves by field, area or formation where the data used in calculating the reserves are confidential. The sum of the reserves in non-producing fields or areas having an initial marketable reserve of less than 10 billion cubic feet, and the sum of the reserves in confidential fields, areas, or zones are shown at the end of the table. These reserves are also included in the provincial total.

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	Acheson										
2	Viking										
3	Blairmore										
4	Blairmore Assoc										
5	Blairmore Soln										
6	D-3 A Soln	1950	5080								
7	Aden										
8	Bow Island										
9	Basal Colorado										
10	Blairmore										
11	Sunburst-Swift										
12	Mississippian										
13	Alderson										
14	Milk River A	1941	970	0.578	420	54	6,460	52	0.20	0.50	0.94
15	Milk River (Other)										
16	2WS A	1956	1970	0.577	830	80	321,500	5	0.20	0.40	0.90
17	Bow Island										
18	Basal Colorado										
19	Alexander										
20	Basal Quartz A	1954	3830		GIP BASED ON MATERIAL BALANCE						
21	Mannville (Other)										
22	Alix										
23	Blairmore										
24	D-2 Assoc										
25	D-2 Soln										
26	Ante Creek										
27	Peace River										
28	Gething 36-67-24	1961	5670	0.623	2200	123	500	35	0.15	0.30	0.83
29	Gething										
30	Triassic										
31	Antelope										
32	Viking A	1957	2360	0.591	950	82	4,620	8	0.22	0.50	0.88
33	Banff										
34	Athabasca										
35	Grand Rapids										
36	Wabamun										
37	Athabasca East										
38	Mannville										
39	D-1										
40	Atim										
41	Viking										
42	Mannville										
43	Atlee-Buffalo										
44	Viking A	1951	2600	0.597	990	80	31,910	5	0.25	0.50	0.88
45	Viking B	1954	2320	0.595	1010	80	17,310	4	0.25	0.50	0.87
46	Viking (Other)										
47	Basal Colorado										
48	Basal Mannville A	1953	3220	0.590	1410	90	9,550	7	0.19	0.50	0.85
49	Basal Mannville B	1954	3290	0.591	1430	90	4,990	8	0.19	0.50	0.85
50	Mannville (Other)										

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
5	0.75	0.05	4	2	2	1020	2	1966 Gas sold to Northwestern	2
5	0.80	0.05	4	-	4	1040	4	1967 Utilities Limited	3
27	0.85	0.10	20	5**	17	1050	18	1967	4
7	0.65	0.55	2						5
76	0.70	0.55	24	7	17	1070*	18	1966	6
									7
5	0.85	0.05	4	-	4	1000	4	1968 Gas sold to Canadian -	8
7	0.85	0.05	6	2	4	1000	4	1968 Montana Gas Company	9
1	0.75	0.05	1	-	1	1020	1	1966 Limited	10
2	0.90	0.05	2	1	1	1040	1	1968	11
13	0.90	0.10	10	7	3	1040	3	1961	12
									13
46	0.50	0.05	22	5	17	960	16	1968 Supplies local Utility	14
1	0.80	0.05	1	-	1	960	1	1966	15
500	0.70	0.05	330	3	327	960	314	1967 Gas sold to Trans-Canada	16
25	0.80	0.05	20	-	20	1000	20	1964 Pipe Lines Limited	17
13	0.85	0.05	10	-	10	1030	10	1965	18
									19
140	0.85	0.05	110	107	3	1060*	3	1967 Gas sold to North Canad-	20
6	0.40	0.05	2	2	< 1	1060*	< 1	1961 ian Oils Limited and	21
								Calgary Power Ltd.	
									22
10	0.90	0.05	8	-	8	1090*	9	1962	23
7	0.85	0.10	5	-	5	1130*	6	1965	24
6	0.65	0.65	1	-	1	1130*	1	1968	25
									26
11	0.85	0.05	8	-	8	1100	9	1964	27
13	0.85	0.05	11	-	11	1100	12	1967	28
13	0.85	0.05	10	-	10	1100	11	1967	29
5	0.85	0.05	4	-	4	1140	5	1967	30
									31
13	0.80	0.05	10	1	9	1020	9	1967 Gas sold to Trans-Canada	32
17	0.80	0.05	13	5	8	1020	8	1967 Pipe Lines Limited	33
									34
6	0.85	0.05	5	2	3	1000	3	1957 Supplies local Utility	35
4	0.90	0.05	3	-	3	980	3	1957	36
									37
1	0.80	0.05	1	-	1	1090	1	1957	38
4	0.60	0.05	2	1	1	1000	1	1968 Supplies local Utility	39
									40
2	0.80	0.05	1	-	1	1000	1	1957	41
2	0.85	0.05	2	1	1	1070*	1	1963 Gas sold to Canadian	42
								Industrial Gas & Oil Ltd.	
									43
61	0.75	0.05	43	11	32	970	31	1967 Gas sold to Trans-Canada	44
29	0.75	0.05	21	1	20	970	19	1967 Pipe Lines Limited	45
4	0.75	0.05	3	-	3	970	3	1967	46
6	0.80	0.05	5	-	5	1020	5	1967	47
29	0.80	0.05	22	-	22	960	21	1967	48
17	0.80	0.05	13	-	13	960	12	1967	49
3	0.80	0.05	2	-	2	960	2	1967	50

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	BANTRY										
2	MILK RIVER A	1940	960	0.565	400	55	185,500	15	0.15	0.35	0.94
3	2WS										
4	VIKING										
5	BASAL COLORADO										
6	MANNVILLE E	1946	3,290	0.640	1590	90	2,620	9	0.20	0.30	0.81
7	MANNVILLE (OTHER)										
8	MANNVILLE A ASSOC	1948	3,210	0.726	1560	85	5,980	6	0.26	0.30	0.79
9	MANN ASSOC (OTHER)										
10	BAPTISTE										
11	MANNVILLE										
12	WABAMUN A	1959	1,940	0.567	510	70	3,840	23	0.15	0.30	0.93
13	BASHAW										
14	VIKING										
15	MANNVILLE										
16	MANNVILLE ASSOC										
17	D-3 A ASSOC	1951	5,760	0.780	2330	140	2,740	17	0.05	0.15	0.85
18	D-3 ASSOC (OTHER)										
19	BEAVER CROSSING										
20	COLONY A										
21	BEAVEFHILL LAKE-FORT SASKATCHEWAN										
22	VIKING (MAIN)	1946	2,590	0.609	810	90	120,410	8	0.22	0.30	0.90
23	VIKING (OTHER)										
24	MANNVILLE										
25	BELLIS										
26	MANNVILLE										
27	NISKU A	1965	2,100	0.569	560	80	14,750	23	0.09	0.20	0.93
28	NISKU (OTHER)										
29	BELLOY										
30	NOTIKEWIN										
31	GETHING A	1951	2,990	0.550	1260	107	12,350	8	0.14	0.40	0.88
32	GETHING B	1951	3,100	0.570	1330	108	6,170	14	0.14	0.40	0.87
33	DEBOLT A	1951	4,700	0.634	1970	95	1,100	39	0.10	0.20	0.79
34	BENJAMIN CREEK										
35	RUNDLE 33-28-7	1961	10,600	0.676	3910	232	2,270	112	0.05	0.20	0.93
36	BERLAND RIVER										
37	LEDUC A	1958	12,290	0.700	5340	250	1,100	562	0.08	0.20	1.00
38	BERLAND RIVER WEST										
39	WABAMUN 10-58-25	1958	12,320	0.701	4800	260	1,100	71	0.04	0.20	0.98
40	BERRY										
41	VIKING										
42	MANNVILLE										
43	BIG BEND										
44	WABISKAW 31-68-1	1957	2,430	0.590	800	80	1,100	29	0.20	0.30	0.86
45	MCMURRAY A	1953	2,710	0.600	900	85	3,920	17	0.20	0.35	0.88
46	MANNVILLE (OTHER)										
47	WABAMUN										
48	BIGORAY										
49	PASKAPOO										
50	BLAIRMORE										
51	RUNDLE										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
46	0.80	0.05	35	1	34	960	33	1961 Supplies local Utilities	2
1	0.80	0.05	1	-	1	970	1	1967	3
26	0.80	0.05	20	-	20	970	19	1965	4
7	0.80	0.05	5	1	4	970	4	1964 Gas sold to Canadian	5
18	0.80	0.10	13	2	11	1030	11	1961 Western Natural Gas	6
4	0.85	0.05	3	-	3	1030	3	1961 Company Limited	7
34	0.85	0.10	26	-	26	1060*	28	1968	8
16	0.85	0.05	13	-	13	1060*	14	1968	9
									10
6	0.80	0.05	5	-	5	970	5	1968 Presently considered	11
15	0.80	0.05	11	-	11	980	11	1966 beyond economic reach.	12
									13
1	0.75	0.05	1	-	1	970	1	1963	14
13	0.90	0.05	11	-	11	1000	11	1966	15
12	0.80	0.05	9	-	9	1030*	9	1966	16
16	0.80	0.15	11	-	11	1100*	12	1966	17
2	0.80	0.15	1	-	1	1100*	1	1966	18
									19
1	0.70	0.05	1	-	1	1000	1	1963 Supplies local Utility	20
									21
610	0.85	0.05	490	126	364	1010	367	1966 Gas sold to Northwestern	22
37	0.85	0.05	30	-	30	1010	30	1966 Utilities Limited and	23
4	0.85	0.05	3	-	3	1010	3	1966 Canadian Industrial Gas and Oil Ltd.	24
									25
7	0.80	0.05	5	-	5	1015	5	1966	26
43	0.85	0.05	35	-	35	1000	35	1966	27
1	0.70	0.05	1	-	1	1000	1	1966	28
									29
9	0.80	0.05	7	-	7	980	7	1961	30
32	0.80	0.05	24	-	24	980	24	1961	31
31	0.90	0.05	27	-	27	980	26	1961	32
23	0.90	0.05	20	-	20	1120	22	1961	33
									34
100	0.85	0.20	70	-	70	1070	75	1966	35
									36
440	0.90	0.25	300	-	300	990	297	1959	37
									38
24	0.90	0.30	15	-	15	1020	15	1959 Presently considered beyond economic reach	39
									40
3	0.85	0.05	2	-	2	1020	2	1967	41
11	0.85	0.05	9	-	9	1030	9	1967	42
								Presently considered	43
12	0.90	0.05	10	-	10	990	10	1957 beyond economic reach	44
26	0.80	0.05	19	-	19	990	19	1965 Includes areas formerly	45
32	0.75	0.05	23	-	23	990	23	1968 known as Chisholm, Flat-	46
20	0.80	0.05	15	-	15	1000	15	1968 bush and Tieland	47
									48
2	0.60	0.05	1	-	1	1000	1	1959	49
16	0.85	0.05	13	-	13	1080	14	1960	50
19	0.80	0.10	14	-	14	1080	15	1959	51

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	Bigstone										
2	Dunvegan A	1959	6,440	0.690	2,600	144	6,390	12	0.15	0.45	0.79
3	Gething A	1960	7,780	0.663	2,500	216	1,100	20	0.14	0.30	0.89
4	Gething (Other)										
5	Wabamun										
6	D-3 A	1960	11,080	0.689	4,800	240	7,090	86	0.07	0.15	0.97
7	Bindloss										
8	Viking A	1952	2,260	0.590	990	80	57,050	14	0.29	0.45	0.88
9	Viking B	1957	2,530	0.590	1,000	80	6,110	10	0.29	0.45	0.88
10	Viking (Other)										
11	Basal Mannville A	1954	2,770	0.585	1,460	85	5,310	7	0.23	0.40	0.85
12	Banff										
13	Bittern Lake										
14	Viking										
15	Blauconitic A	1952	4,010	0.636	1,310	115	3,530	17	0.25	0.40	0.86
16	Glauconitic B	1952	4,180	0.636	1,370	115	1,210	29	0.24	0.40	0.85
17	GLC (Other)										
18	Ellerslie A	1952	4,140	0.676	1,350	115	2,370	11	0.19	0.35	0.83
19	Ellerslie (Other)										
20	Black Butte										
21	2WS										
22	Bow Island A	1944	2,200	0.563	660	73	3,300	25	0.20	0.35	0.92
23	Basal Colorado A	1960	2,540	0.577	930	80	2,840	15	0.20	0.40	0.89
24	BSL COLO (Other)										
25	Mannville (Other)										
26	Sunburst-Swift A	1962	2,960	0.571	1,030	86	2,040	19	0.20	0.30	0.87
27	Sawtooth A	1944	3,200		GIP BASED ON MATERIAL BALANCE						
28	Rundle A	1944	3,280	0.578	1,200	90	2,750	18	0.10	0.20	0.87
29	Black Diamond										
30	Rundle A	1967	9,020	0.740	3,630	194	500	59	0.10	0.15	0.87
31	Blueridge										
32	Mannville										
33	Jurassic A	1957	5,500	0.655	1,800	148	500	26	0.28	0.30	0.85
34	Jurassic (Other)										
35	Mississippian										
36	Bonnie Glen										
37	Cardium Soln										
38	Viking										
39	Mannville										
40	Wabamun										
41	Graminia										
42	D-3										
43	D-3 A Assoc	1951	6,700	0.700	2,440	139	2,990	216	0.09	0.10	0.79
44	D-3 A Soln	1952	7,000								
45	Bonnyville										
46	Mannville										
47	Mannville Assoc										
48	Boundary Lake										
49	Cadomin										
50	Triassic										
51	Kiskatinaw D	1964	6,210	0.600	2,350	140	2,240	16	0.17	0.20	0.85
52	Kiskatinaw (Other)										
53	Golata										
54	Bow Island										
55	Bow Island	1909	1,920		RESERVE ESTIMATE BASED ON PRODUCTION AND INJECTION DATA						

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
53	0.90	0.05	45	-	45	1140	51	1966		2
13	0.90	0.05	11	-	11	1070	12	1961		3
11	0.90	0.05	9	-	9	1100	10	1961		4
11	0.85	0.40	5	-	5	1050	5	1964		5
390	0.85	0.25	250	-	250	990*	248	1964		6
										7
420	0.75	0.05	300	105	195	980	191	1967	Gas sold to Trans-Canada	8
32	0.70	0.05	21	2	19	980	19	1967	Pipelines Limited	9
6	0.75	0.05	5	-	5	980	5	1967		10
26	0.90	0.05	23	-	23	990	23	1967		11
3	0.85	0.05	2	-	2	1000	2	1967		12
										13
11	0.80	0.05	8	-	8	1020	8	1967	Gas sold to Canadian	14
38	0.85	0.05	30	2	28	1070	30	1967	Industrial Gas & Oil Ltd,	15
21	0.85	0.05	17	1	16	1070	17	1967	Plains Western Gas &	16
19	0.85	0.05	15	-	15	1070	16	1967	Electric and Northwestern	17
14	0.85	0.05	12	-	12	1070	13	1967	Utilities, Limited	18
24	0.85	0.05	19	-	19	1070	20	1967		19
										20
2	0.80	0.05	2	-	2	960	2	1961		21
21	0.85	0.05	17	3	14	980	14	1963	Gas sold to Canadian	22
15	0.85	0.05	12	3	9	1000	9	1968	Montana Gas Company	23
10	0.85	0.05	8	5	3	1000	3	1968	Limited	24
7	0.85	0.05	5	-	5	1030	5	1963		25
18	0.90	0.05	15	9	6	1000	6	1963		26
28	0.80	0.05	21	17	4	1000	4	1967		27
16	0.80	0.05	12	4	8	1020	8	1968		28
										29
24	0.85	0.15	17	-	17	1100	19	1967		30
										31
3	0.80	0.05	2	-	2	1100	2	1964		32
14	0.90	0.05	12	-	12	1100	13	1966		33
2	0.80	0.10	1	-	1	1100	1	1968		34
4	0.75	0.10	3	-	3	1130	3	1966		35
										36
2	0.65	0.10	1	-	1	1040*	1	1965		37
2	0.85	0.10	1	-	1	1050	1	1963		38
5	0.85	0.10	4	3	1	1100*	1	1964	Gas sold to Northwestern	39
1	0.85	0.10	1	-	1	1100*	1	1967	Utilities, Limited	40
1	0.85	0.10	1	-	1	1100*	1	1967		41
14	0.70	0.15	9	7	2	1100*	2	1967		42
430	0.85	0.15	310	-	310	1220*	378	1966		43
540	0.70	0.25	280	50	230	1220*	281	1966		44
										45
4	0.80	0.05	3	3	< 1	980	< 1	1964	Supplies local Utility	46
1	0.80	0.05	1	-	1	980	1	1963		47
										48
11	0.80	0.10	8	-	8	1060	8	1964		49
1	0.85	0.10	1	-	1	1050	1	1966		50
36	0.85	0.05	29	9	20	1080	22	1966	Gas sold to Westcoast	51
4	0.85	0.05	3	2	1	1080	1	1966	Transmission Company	52
18	0.90	0.05	15	12	3	1080	3	1966	Limited	53
										54
20	0.80	0.05	15	-3	18	1030	19	1953	Canadian Western Natural Gas company Limited Storage Reservoir.	55

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DIS-COVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESSIBILITY FACTOR FRACTION
1	BOYLE										
2	MANNVILLE										
3	DETRITAL										
4	NISKU										
5	BRAEBURN										
6	CADOMIN										
7	BALDONNEL A	1954	5,680	0.611	2150	146	4,890	8	0.16	0.30	0.86
8	BELLOY A	1954	7,280	0.579	2970	178	3,560	35	0.11	0.50	0.90
9	BRAZEAU RIVER										
10	ELKTON A	1959	10,150	0.640	3860	213	55,900	12	0.11	0.10	0.94
11	ELKTON B	1965	9,870	0.675	3870	230	9,730	17	0.12	0.20	0.95
12	SHUNDA A	1965	10,200	0.652	3910	204	22,010	9	0.08	0.30	0.94
13	BROOKS										
14	MILK RIVER										
15	BROWN CREEK										
16	RUNDLE 20-44-17	1960	10,840	0.641	4550	117	2,000	89	0.04	0.20	0.98
17											
18	BRUCE										
19	VIKING										
20	MANNVILLE										
21	BURNT TIMBER										
22	RUNDLE,A	1959	10,900	0.717	3800	105	12,160	61	0.06	0.15	0.91
23	CALAIS										
24	GETHING										
25	CADOMIN A										
26	CALLING LAKE										
27	MANNVILLE										
28	D-2 A	1964	1,550	0.577	360	70	24,810	25	0.13	0.45	0.95
29	CAMPBELL-NAMAO										
30	BLAIRMORE										
31	BLAIRMORE E ASSOC	1951	3,600	0.665	1180	119	1,450	31	0.19	0.25	0.88
32	BLAIR ASSOC(OTHER)										
33	BLAIRMORE SOLN										
34											
35	CARBON										
36	BELLY RIVER										
37	VIKING										
38	BASAL COLORADO										
39	GLAUCONITIC	1955	4,750	0.679	1480	120	11,800	22	0.20	0.35	0.83
40	MANNVILLE(OTHER)										
41	RUNDLE										
42	CAROLINE										
43	VIKING										
44	VIKING A ASSOC	1957	8,070	0.672	2500	165	40,600	7	0.11	0.25	0.83
45	BASAL MANNVILLE B	1958	9,460	0.779	4260	187	500	26	0.15	0.30	0.92
46	BASAL MANNVILLE C	1964	8,900	0.781	4040	179	500	27	0.15	0.30	0.89
47	MANNVILLE (OTHER)	1964									
48	ELKTON D	1960	9,170	0.828	3600	193	500	29	0.12	0.20	0.86
49	ELKTON (OTHER)										
50	CARSON CREEK										
51	BEAVERHILL LAKE A	1957	8,550	0.972	3790	199	15,840	20	0.08	0.20	0.85
52	BEAVERHILL LAKE B	1957	8,610	0.972	3790	199	6,980	24	0.08	0.20	0.85
53	CARSON CREEK NORTH										
54	BHL LK A ASSOC	1958	8,580	0.789	3710	190	3,710	11	0.08	0.20	0.85
55	BHL LK A SOLN	1958	8,630								
56	BHL LK B SOLN	1958	8,740								

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
6	0.80	0.05	5	-	5	1000	5	1966		2
2	0.85	0.05	1	-	1	1000	1	1966		3
9	0.85	0.05	8	-	8	990	8	1966		4
										5
4	0.80	0.05	3	1	2	1060*	2	1966	Gas sold to Westcoast	6
29	0.80	0.10	21	4	17	1090*	19	1968	Transmission Company	7
55	0.80	0.05	42	2	40	1030*	41	1968	Limited	8
										9
630	0.80	0.10	450	-	450	1050*	473	1967		10
140	0.80	0.10	100	-	100	1040*	104	1968		11
96	0.75	0.10	65	-	65	1080*	70	1967		12
										13
9	0.80	0.05	7	4	3	990	3	1961	Supplies Local Utility	14
										15
59	0.80	0.15	40	-	40	970	39	1964	Presently considered	16
									beyond economic Reach	17
										18
25	0.80	0.05	19	-	19	1000	19	1967	Presently considered	19
9	0.80	0.05	7	-	7	1020	7	1967	beyond economic Reach	20
										21
370	0.85	0.20	250	-	250	1030	257	1966		22
										23
14	0.85	0.05	11	-	11	1000	11	1960	Supplies Local Utility	24
12	0.85	0.05	10	-	10	1000	10	1964		25
										26
2	0.85	0.05	2	-	2	1000	2	1967	Presently considered	27
49	0.75	0.05	35	-	35	1000	35	1967	beyond economic Reach	28
										29
4	0.85	0.05	3	-	3	1020	3	1964		30
23	0.85	0.05	18							31
4	0.80	0.05	3	18**	7	1020*	7	1964	Gas sold to Canadian	32
8	0.60	0.10	4						Industrial Gas & Oil	33
									Ltd.	34
										35
1	0.80	0.05	1	-	1	990	1	1964		36
5	0.80	0.05	4	-	4	1020	4	1964		37
4	0.85	0.05	3	-	3	1020	3	1964		38
160	0.85	0.05	130	22	108	1120	121	1966	Gas sold to Canadian	39
4	0.85	0.05	3	-	3	1100	3	1964	Western Natural Gas	40
4	0.85	0.05	3	-	3	1110	3	1965	Company Limited	41
										42
2	0.80	0.05	1	-	1	1040*	1	1967		43
160	0.80	0.05	120	-	120	1040*	125	1967		44
15	0.85	0.10	12	-	12	1070	13	1964		45
16	0.85	0.10	12	-	12	1070	13	1965		46
8	0.85	0.10	6	-	6	1040*	6	1965		47
14	0.85	0.10	11	-	11	1020*	11	1965		48
12	0.85	0.15	9	-	9	1020*	9	1965		49
										50
210	0.85	0.15	150	7	143	1080*	154	1964	Reservoirs being cycled	51
110	0.85	0.15	80	-14	94	1080*	102	1964	and gas sold to North-	52
									western Utilities	53
28	0.85	0.15	20	-	20	1100*	22	1962	Limited & A & S Gas Co.	54
110	0.45	0.20	38	3	35	1100*	39	1965	Gas injected into	55
330	0.40	0.20	110	6	104	1100*	114	1965	Carson Creek	56

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	CARSTAIRS										
2	BLAIRMORE										
3	ELKTON A	1958	8,100		GIP BASED ON MATERIAL BALANCE						
4	ELKTON ASSOC										
5	CASTOR										
6	VIKING										
7	MANNVILLE										
8	CESSFORD										
9	VIKING B	1951	3,130	0.582	1190	79	4,140	8	0.20	0.50	0.85
10	VIKING G	1956	2,790	0.587	1100	80	2,350	12	0.24	0.50	0.86
11	VIKING H	1961	2,630	0.592	1100	80	6,460	6	0.20	0.50	0.86
12	VIKING I	1961	2,710	0.590	1190	79	3,800	10	0.20	0.50	0.85
13	VIKING (OTHER)										
14	BASAL COLORADO E	1950	2,970	0.613	1260	86	33,410	8	0.24	0.40	0.84
15	BASAL COLORADO G	1962	3,280	0.616	1260	92	5,410	5	0.20	0.35	0.85
16	BASAL COLORADO J	1950	3,100	0.618	1330	86	6,020	4	0.24	0.35	0.84
17	BSL COLO (OTHER)										
18	BSL COLO A ASSOC	1950	2,860	0.610	1260	86	135,000	10	0.26	0.30	0.84
19	GLAUCONITIC A	1960	3,600	0.665	1280	95	9,740	6	0.16	0.40	0.84
20	GLAUCONITIC B	1962	3,580	0.668	1430	97	5,810	6	0.16	0.40	0.82
21	MANNVILLE A	1959	3,870	0.655	1420	105	15,590	13	0.17	0.40	0.83
22	MANNVILLE F	1951	3,290	0.633	1440	85	4,220	10	0.23	0.30	0.83
23	MANNVILLE G	1950	3,400	0.648	1420	92	3,770	13	0.24	0.30	0.84
24	MANNVILLE H	1950	3,070	0.625	1440	80	6,900	13	0.25	0.30	0.84
25	MANNVILLE J	1958	3,400	0.641	1540	100	5,620	10	0.22	0.30	0.84
26	MANNVILLE T	1959	3,040	0.627	1440	80	500	34	0.22	0.30	0.84
27	MANNVILLE (OTHER)										
28	MANNVILLE ASSOC										
29	CHAMBERS										
30	BLAIRMORE										
31	ELKTON										
32	CHARLOTTE LAKE										
33	MANNVILLE										
34	CHIGWELL										
35	MANNVILLE A	1952	5,160	0.728	1710	143	3,260	22	0.17	0.35	0.83
36	MANNVILLE (OTHER)										
37	CHINOOK RIDGE										
38	PADDY										
39	CADOTTE 12-65-13	1956	9,200	0.800	3300	228	1,100	23	0.20	0.80	0.85
40	NOTIKEWIN 12-65-13	1956	9,460	0.800	3400	233	500	32	0.20	0.30	0.86
41	CLIVE										
42	VIKING										
43	MANNVILLE										
44	D-2 A ASSOC	1951	6,040	0.750	2480	152	4,190	20	0.06	0.15	0.73
45	D-2 SOLN										
46	D-3 A ASSOC	1952	6,140	0.805	2550	152	3,830	19	0.06	0.15	0.72
47	D-3 A SOLN	1952	6,150								
48	COLD LAKE										
49	MANNVILLE										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)		
INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/68 BCF	REMAINING MARKETABLE GAS MAY 31/68 BCF	GROSS HEATING VALUE BTU CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
16	0.85	0.15	11	-	11	1100	12	1967	2
1140	0.90	0.15	870	228	642	1070*	687	1967 Gas sold to Trans-Canada	3
6	0.85	0.15	5	-	5	1070*	5	1967 Pipe Lines Limited	4
									5
9	0.80	0.05	7	-	7	1040	7	1968	6
4	0.85	0.05	3	-	3	1090	3	1963 Supplies local Utility	7
									8
13	0.85	0.05	11	3	8	1020*	8	1965 Gas sold to Trans-Canada	9
13	0.85	0.05	10	3	7	1020*	7	1965 Pipe Lines Limited	10
13	0.80	0.05	10	-	10	1020*	10	1967	11
14	0.85	0.05	11	-	11	1020*	11	1965	12
55	0.80	0.05	42	4	38	1020*	39	1967	13
170	0.85	0.05	140	36	104	1030*	107	1965	14
14	0.85	0.05	11	1	10	1030*	10	1966	15
15	0.85	0.05	13	-	13	1030*	13	1965	16
20	0.85	0.05	16	4	12	1030*	12	1965	17
1010	0.85	0.05	820	306	514	1030*	530	1965	18
22	0.85	0.05	18	-	18	1080*	19	1965	19
17	0.85	0.05	14	-	14	1080*	15	1965	20
97	0.85	0.05	78	13	65	1000*	65	1965	21
33	0.85	0.05	25	3	22	1000*	22	1962	22
38	0.85	0.05	31	21	10	1000*	10	1962	23
76	0.85	0.05	61	19	42	1000*	42	1962	24
41	0.80	0.05	31	13	18	1000*	18	1962	25
13	0.90	0.05	11	-	11	1000*	11	1961	26
96	0.80	0.05	75	22	53	1030*	55	1966	27
24	0.80	0.05	19	-	19	1030*	20	1966	28
									29
6	0.85	0.10	4	-	4	1030	4	1967	30
13	0.85	0.15	9	-	9	1080	10	1967	31
									32
3	0.75	0.05	2	-	2	1000	2	1967 Supplies Canadian Base at Cold Lake	33
									34
42	0.90	0.10	34	12	22	1110	24	1959 Gas sold to Trans-Canada	35
13	0.75	0.10	9	1	8	1110	9	1968 Pipe Lines Limited	36
									37
13	0.80	0.10	9	-	9	1020	9	1961 Presently considered	38
32	0.80	0.10	23	-	23	1020	23	1961 beyond economic reach	39
20	0.80	0.10	15	-	15	1020	15	1961	40
									41
4	0.80	0.05	3	-	3	990	3	1966	42
5	0.85	0.05	4	-	4	1020	4	1966	43
38	0.85	0.30	23	-	23	1050*	24	1967	44
35	0.40	0.55	6	-	6	1050*	6	1968	45
32	0.85	0.35	17	-	17	1050*	18	1967	46
64	0.40	0.60	10	-	10	1050*	11	1968	47
									48
8	0.70	0.05	6	4	2	1000	2	1966 Supplies local Utility	49

TABLE A -1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DISCOVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESSIBILITY FACTOR FRACTION
1	Comrey										
2	2WS										
3	Bow Island	1952	2,480	0.586	770	80	6,980	16	0.25	0.50	0.92
4	Bow Island (Other)										
5	Sawtooth										
6	Connorsville										
7	Viking										
8	Lower Mannville A	1956	3,650	0.613	1410	104	10,110	11	0.16	0.35	0.85
9	Mannville (Other)										
10	Countess										
11	Bow Island A	1951	2,890	0.600	1040	86	14,490	6	0.23	0.50	0.87
12	Bow Island C	1955	2,860	0.598	1040	84	6,080	7	0.22	0.50	0.87
13	Bow Island F	1967	2,830	0.602	1170	83	2,230	13	0.27	0.50	0.86
14	Bow Island (Other)										
15	Basal Colorado A	1951	3,500		GIP BASED ON MATERIAL BALANCE						
16	BSL COLO (Other)										
17	Mannville										
18	BSL QTZ B Assoc	1958	4,280	0.671	1470	107	1,370	13	0.21	0.30	0.82
19	MANN Assoc (Other)										
20	MISS Assoc										
21	Craigend										
22	Mannville										
23	Mannville Assoc										
24	Grosmont A	1961	1,660	0.575	410	76	81,000	31	0.12	0.55	0.94
25	Craig Lake										
26	Viking										
27	Crossfield										
28	Cardium Soln	1956	6,670								
29	Basal Quartz A	1957	7,330	0.700	2890	150	12,160	9	0.11	0.30	0.82
30	BSL QTZ (Other)										
31	Rundle A	1956	8,410	0.785	3320	178	33,600	39	0.12	0.15	0.86
32	Rundle B	1957	7,440	0.701	3040	165	21,220	71	0.08	0.15	0.88
33	Rundle D	1951	8,200	0.705	3310	178	500	44	0.08	0.20	0.88
34	Wabamun A	1954	8,500	0.897	3630	165	102,680	34	0.06	0.15	0.71
35	Crossfield East										
36	Blairmore										
37	Elkton A	1960	7,490		GIP BASED ON MATERIAL BALANCE						
38	Elkton C	1967	7,590	0.738	2776	170	1,100	33	0.09	0.20	0.82
39	Wabamun A	1961	9,000	0.905	3630	180	57,750	53	0.05	0.15	0.72
40	Dixonville										
41	Mannville										
42	Triassic										
43	Leduc										
44	Donalda										
45	Viking B	1960	3,280	0.591	900	97	10,770	6	0.22	0.40	0.91
46	Viking (Other)										
47	Mannville										
48	Dowling Lake										
49	Mannville										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
5	0.80	0.05	4	-	4	940	4	1960	2
34	0.75	0.05	24	16	8	940	8	1968 Gas sold to Canadian	3
[illegible]	0.80	0.05	1	-	1	940	1	1960 Montana Gas Company	4
1	0.80	0.05	1	-	1	1000	1	1960 Limited	5
									6
8	0.80	0.05	6	2	4	1000	4	1964 Gas sold to Trans-Canada	7
52	0.85	0.05	42	2	40	1100	44	1965 Pipe Lines Limited	8
15	0.85	0.05	12	1	11	1100	12	1965	9
									10
34	0.80	0.05	26	4	22	1010*	22	1968 Gas sold to Trans-Canada	11
17	0.80	0.05	13	1	12	1010*	12	1968 Pipe Lines Limited	12
15	0.85	0.05	12	-	12	1010*	12	1968	13
29	0.80	0.05	22	1	21	1010*	21	1968	14
170	0.85	0.05	140	69	71	1010*	72	1968	15
6	0.90	0.05	5	-	5	1010*	5	1968	16
48	0.85	0.05	38	5	33	1020*	34	1964	17
12	0.85	0.05	10	-	10	1020*	10	1964	18
5	0.85	0.05	4	-	4	1020*	4	1968	19
3	0.80	0.10	2	-	2	1030*	2	1961	20
									21
49	0.75	0.05	34	-	34	1000	34	1967	22
2	0.75	0.05	1	-	1	1000	1	1967	23
210	0.75	0.05	150	-	150	1000	150	1967	24
									25
1	0.75	0.05	1	-	1	1000	1	1966 Supplies Local Utility	26
									27
74	0.30	0.45	12	1	11	1140*	13	1966 Gas sold to Trans-Canada	28
81	0.85	0.10	62	1	61	1020*	62	1966 Pipe Lines Limited	29
36	0.85	0.10	28	1	27	1020*	28	1966 Westcoast Transmission	30
1230	0.90	0.10	1000	149	851	1070*	912	1964 Company Limited and	31
900	0.85	0.15	650	179	471	1070*	504	1967 Alberta and Southern	32
13	0.85	0.10	10	-	10	1020*	10	1964 Gas Co. Ltd.	33
2080	0.85	0.50	890	79	811	980	795	1967	34
									35
6	0.85	0.10	5	-	5	1020*	5	1968	36
150	0.90	0.12	120	33	87	1140*	99	1968 Gas sold to Trans-Canada	37
22	0.85	0.10	17	-	17	1140*	19	1968 Pipe Lines Ltd Limited	38
1730	0.85	0.55	660	4	656	970	636	1968	39
									40
9	0.85	0.05	7	-	7	980	7	1962 Presently considered	41
8	0.90	0.05	7	-	7	1030	7	1962 beyond economic reach	42
4	0.85	0.05	3	-	3	1070	3	1962	43
									44
23	0.80	0.05	18	-	18	970	17	1962 Presently considered	45
17	0.80	0.05	13	-	13	970	13	1962 beyond economic reach	46
10	0.85	0.05	8	-	8	980	8	1962	47
									48
5	0.80	0.05	3	2	1	1030*	1	1960 Supplies local Utility	49

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	Drumheller										
2	Viking										
3	Mannville F	1950	4,220	0.681	1430	120	37,440	9	0.20	0.25	0.82
4	Mannville H	1950	4,370	0.664	1450	123	2,360	15	0.16	0.45	0.84
5	Mannville (Other)										
6	Mannville Assoc										
7	Pekisko										
8	Duhamel										
9	Viking										
10	Mannville										
11	D-2 Assoc										
12	D-3 Soln										
13	Dunvegan										
14	Cadotte										
15	Debolt										
16	Duvernay										
17	Viking										
18	Dyberg										
19	Belly River										
20	Viking										
21	BSL QTZ 15-44-23	1954	4,620	0.618	1480	132	1,200	17	0.18	0.30	0.84
22	Eaglesham										
23	Gething Assoc										
24	Cadomin Assoc										
25	Debolt A	1952	4,480	0.641	1870	134	2,040	11	0.18	0.25	0.85
26	Debolt B	1959	4,700	0.635	1980	127	1,100	17	0.20	0.20	0.83
27	Debolt C	1959	4,700	0.650	2000	127	1,100	23	0.20	0.20	0.81
28	Edson										
29	Gething A	1963	8,400	0.684	3360	182	11,310	27	0.10	0.25	0.88
30	Elkton A	1962	9,380	0.634	3880	225	121,500	22	0.11	0.10	0.94
31	Elkton 26-51-19	1964	10,120	0.630	3990	211	1,100	31	0.08	0.10	0.94
32	Elkton (Other)										
33	Shunda										
34	Edwand										
35	Mannville										
36	Elk Point										
37	Mannville										
38	Ellerslie										
39	Blairmore Assoc										
40	Enchant										
41	Milk River										
42	Bow Island A	1960	2,470	0.589	950	78	28,780	2	0.15	0.30	0.89
43	Bow Island (Other)										
44	Basal Colorado										
45	Mannville										
46	Jurassic										
47	Rundle										
48	Equity										
49	Mannville										
50	Pekisko A	1962	5,420	0.670	1630	142	8,720	19	0.07	0.30	0.84

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)		
INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/68 BCF	REMAINING MARKETABLE GAS MAY 31/68 BCF	GROSS HEATING VALUE BTU CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
3	0.85	0.05	2	-	2	1080	2	1967	GAS SOLD TO TRANS-CANADA
27	0.85	0.05	21	-	21	1080	23	1968	PIPE LINES LIMITED
16	0.85	0.10	12	1	11	1080	12	1968	
26	0.85	0.05	20	-	20	1080	22	1966	
11	0.80	0.05	8	-	8	1080	9	1966	
3	0.80	0.10	2	-	2	1080	2	1963	
4	0.90	0.05	4	-	4	1000	4	1965	
5	0.85	0.05	4	-	4	1030	4	1965	
2	0.90	0.10	2	-	2	1100	2	1957	
6	0.50	0.55	1	-	1	1100	1	1966	
9	0.75	0.05	7	-	7	1010	7	1963	PRESENTLY CONSIDERED
3	0.90	0.05	3	-	3	1040	3	1963	BEYOND ECONOMIC REACH
4	0.80	0.05	3	2	1	1000*	1	1961	GAS SOLD TO WESTERN
									MINERALS LTD. PLANT AND
									SUPPLIES LOCAL UTILITY
3	0.80	0.05	2	-	2	950	2	1960	PRESENTLY CONSIDERED
8	0.90	0.05	7	-	7	1000	7	1960	BEYOND ECONOMIC REACH
12	0.90	0.05	10	-	10	1020	10	1960	
6	0.85	0.05	5	-	5	1000	5	1965	
7	0.85	0.05	5	-	5	1060	5	1965	
17	0.85	0.05	14	-	14	1110	16	1966	
19	0.85	0.05	15	-	15	1110	17	1965	
27	0.85	0.05	22	-	22	1110	24	1965	
210	0.85	0.10	160	-	160	1050	168	1968	
2340	0.90	0.10	1900	122	1778	1030	1831	1967	GAS SOLD TO TRANS-
22	0.85	0.10	17	-	17	1030	18	1966	CANADA PIPE LINES
6	0.85	0.10	5	-	5	1030	5	1966	LIMITED
12	0.80	0.15	8	-	8	1030	8	1966	
4	0.80	0.05	3	-	3	1000	3	1966	SUPPLIES LOCAL UTILITY
3	0.80	0.05	2	1	1	990*	1	1964	SUPPLIES LOCAL UTILITY
2	0.75	0.15	1	-	1	1000	1	1966	GAS SOLD TO EDMONTON
									LIQUID GAS LTD.
5	0.75	0.05	3	-	3	1000*	3	1964	
15	0.75	0.05	11	-	11	1000*	11	1967	GAS SOLD TO TRANS-
15	0.85	0.05	12	3	9	1000*	9	1967	CANADA PIPE LINES
1	0.75	0.05	1	-	1	1000*	1	1962	LIMITED
14	0.80	0.10	11	3	8	1000*	8	1961	
2	0.75	0.10	2	-	2	1000*	2	1961	
5	0.85	0.10	4	1	3	1000*	3	1966	
13	0.85	0.05	11	-	11	1130*	12	1968	
36	0.85	0.10	25	-	25	1130*	28	1967	

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	ERSKINE										
2	VIKING										
3	BLAIRMORE										
4	D-3										
5	D-3 A ASSOC	1953	5,300	0.703	2210	144	2,510	33	0.06	0.20	0.81
6	D-3 A SOLN										
7	ESTHER										
8	BELLY RIVER A	1956	800	0.578	330	54	31,050	3	0.31	0.35	0.95
9	BANFF A	1965	2,770	0.591	1180	87	1,600	26	0.19	0.30	0.87
10	ETHEL LAKE										
11	MANNVILLE										
12	ETZIKOM										
13	BOW ISLAND A	1951	2,230		GIP BASED ON MATERIAL BALANCE						
14	MANNVILLE										
15	EXCELSIOR										
16	VIKING										
17	MANNVILLE A ASSOC	1953	3,450	0.626	1140	81	3,270	24	0.20	0.35	0.87
18	EYREMORE										
19	BOW ISLAND										
20	FAIRYDELL-BON ACCORD										
21	VIKING A	1950	2,680	0.589	810	85	28,830	11	0.20	0.40	0.89
22	VIKING (OTHER)										
23	MANNVILLE										
24	MANNVILLE ASSOC										
25	FENN-BIG VALLEY										
26	VIKING										
27	D-2 A SOLN	1950	5,290								
28	D-3 SOLN										
29	FERRIER										
30	CARDIUM										
31	CARDIUM D ASSOC	1963	6,680	0.710	3170	158	7,710	7	0.16	0.15	0.83
32	CARDIUM E ASSOC	1965	6,790	0.768	3140	150	13,800	21	0.15	0.20	0.80
33	VIKING A SOLN	1955	8,190								
34	JURASSIC										
35	RUNDLE										
36	BANFF										
37	FIGURE LAKE										
38	VIKING										
39	MANNVILLE										
40	D-2 B	1957	2,260	0.574	630	180	6,700	13	0.14	0.45	0.92
41	D-2 (OTHER)										
42	FLAT										
43	MANNVILLE										
44	WABAMUN A	1956	1,870	0.582	490	70	18,940	45	0.23	0.50	0.93
45	FOREMOST										
46	BOW ISLAND	1916	2,080	0.584	690	71	10,400	7	0.24	0.20	0.92

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
4	0.80	0.05	3	-	3	1040	3	1962		2
21	0.80	0.10	15	3	12	1090	13	1966	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED	3
1	0.85	0.20	1	-	1	1070	1	1968		4
29	0.90	0.20	21	-	21	1070	22	1966		5
19	0.50	0.75	2	-	2	1110	2	1966		6
										7
21	0.75	0.05	15	-	15	990	15	1964		8
21	0.85	0.05	17	2	15	1000	15	1966	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED	9
										10
3	0.80	0.05	2	-	2	1000	2	1967	GAS USED FOR LOCAL EXPERIMENTAL PROJECT	11
										12
68	0.75	0.05	48	33	15	930	14	1967	GAS SOLD TO SOUTH ALBERTA PIPE LINES LTD.	13
2	0.75	0.05	1	-	1	1010	1	1961		14
										15
8	0.80	0.05	7	3	4	1000	4	1953	GAS SOLD TO CANADIAN INDUSTRIAL GAS & OIL LTD. AND PLAINS-WESTERN GAS & ELECTRIC CO. LTD.	16
38	0.90	0.05	33	-	33	970	32	1953		17
										18
15	0.70	0.05	10	-	10	960	10	1955	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH	19
										20
100	0.80	0.05	78	29	49	1020	50	1966	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED	21
9	0.80	0.05	7	1	6	1020	6	1963		22
15	0.80	0.05	12	2	10	990	10	1965		23
6	0.80	0.10	5	-	5	990	5	1966		24
										25
19	0.80	0.90	2	1	1	1000*	1	1961	GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED	26
150	0.65	0.85	15	7	8	1110*	9	1966		27
9	0.60	0.85	1	-	1	1110*	1	1966		28
										29
8	0.80	0.10	6	-	6	1000	6	1968		30
74	0.80	0.10	53	-	53	1000	53	1968		31
350	0.80	0.10	250	-	250	1000	250	1968		32
31	0.65	0.25	15	2	13	1130	15	1966	GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD.	33
4	0.75	0.05	3	-	3	1080	3	1956		34
2	0.80	0.10	2	-	2	1100	2	1960		35
8	0.85	0.10	6	-	6	1100	7	1967		36
										37
4	0.75	0.05	3	-	3	960	3	1966		38
13	0.80	0.05	10	-	10	1000	10	1966		39
13	0.85	0.05	11	-	11	1000	11	1966		40
12	0.85	0.05	8	-	8	1000	8	1966		41
										42
13	0.80	0.05	10	-	10	1020	10	1968	SUPPLIES LOCAL UTILITY	43
140	0.80	0.05	110	-	110	1040	114	1968		44
										45
31	0.85	0.05	27	7	20	950	19	1953	GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED	46

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	Fort Kent										
2	Colony										
3	Fox Creek										
4	Viking A	1957	5,620	0.671	1480	140	21,790	11	0.15	0.40	0.85
5	Notikewin										
6	Cadomin										
7	Triassic										
8	Garrington										
9	Mannville										
10	Mannville Assoc										
11	Rundle										
12	Leduc										
13	Leduc 23-35-4	1954	10,010	0.753	3760	220	500	125	0.05	0.20	0.94
14	LED Assoc 36-35-4	1956	9,880	0.769	3700	220	500	85	0.05	0.20	0.95
15	Ghost Pine										
16	Viking										
17	U MANN G & P[illegible]	1964	4,580	0.685	1510	120	11,300	6	0.20	0.35	0.81
18	U MANN Q	1955	4,780	0.674	1520	125	2,390	18	0.20	0.35	0.81
19	U MANN U	1965	4,640	0.695	1550	115	2,850	14	0.20	0.35	0.81
20	Mannville (Other)										
21	U MANN W Assoc	1963	4,580	0.759	1520	110	5,490	6	0.18	0.50	0.75
22	L MANN E Assoc	1955	4,850	0.680	1550	125	2,270	16	0.20	0.45	0.82
23	MANN Assoc (Other)										
24	Pekisko B	1962	5,060	0.689	1620	125	6,520	15	0.05	0.30	0.82
25	Rundle (Other)										
26	Gilby										
27	Cardium										
28	Viking										
29	Viking Assoc										
30	Basal Mannville D	1962	6,930	0.704	2250	158	2,360	27	0.11	0.30	0.83
31	Basal Mannville H	1956	6,880	0.712	2300	157	5,630	20	0.12	0.35	0.81
32	Mannville (Other)										
33	Mannville Assoc										
34	BSL MANN A - JUR D	1956	7,130	0.718	2310	157	5,860	53	0.14	0.30	0.81
35	Jurassic A	1953	6,840	0.729	2300	150	6,050	17	0.14	0.30	0.81
36	Jurassic C	1955	6,920	0.729	2280	155	2,010	13	0.15	0.30	0.82
37	Jurassic E	1961	7,030	0.729	2320	155	7,840	18	0.13	0.35	0.81
38	Jurassic (Other)										
39	Jurassic B Assoc	1958	6,990	0.729	2310	160	1,220	16	0.16	0.20	0.82
40	Rundle C	1955	6,970	0.729	2290	160	8,070	55	0.10	0.15	0.82
41	Rundle D	1955	6,770	0.725	2280	155	11,240	32	0.07	0.20	0.82
42	Rundle H	1961	7,210	0.720	2320	170	2,420	29	0.04	0.20	0.83
43	Rundle (Other)										
44	Wabamun										
45	Glenevis										
46	Mannville										
47	Glen Park										
48	Mannville										
49	Leduc Soln										

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
6	0.75	0.05	4	2	2	980	2	1966 SUPPLIES LOCAL UTILITY	2
									3
97	0.75	0.05	69	-	69	1110	77	1967	4
7	0.80	0.05	5	-	5	1180	6	1967	5
42	0.85	0.05	34	-	34	1160	39	1967	6
3	0.90	0.10	2	-	2	1160	2	1967	7
									8
12	0.85	0.10	9	-	9	1010	9	1964	9
3	0.90	0.15	2	-	2	1010	2	1967	10
2	0.85	0.10	1	-	1	1020	1	1964	11
7	0.85	0.20	5	-	5	1020	5	1964	12
23	0.85	0.20	15	-	15	1020	15	1964	13
15	0.85	0.20	10	-	10	1020	10	1964	14
									15
9	0.80	0.05	7	-	7	1020	7	1967	16
42	0.80	0.10	30	5	25	1020	26	1967 GAS SOLD TO TRANS-CANDAD	17
27	0.80	0.10	20	-	20	1030	21	1967 PIPE LINES LIMITED	18
28	0.80	0.10	20	-	20	1030	21	1967	19
210	0.80	0.10	150	3	147	1030	151	1967	20
15	0.80	0.15	10	-	10	1050	11	1967	21
20	0.80	0.10	14	-	14	1050	15	1967	22
23	0.75	0.15	15	1	14	1050	15	1967	23
17	0.80	0.10	12	-	12	1070	13	1967	24
9	0.80	0.10	7	1	6	1070	6	1967	25
									26
2	0.85	0.10	2	-	2	1000	2	1965	27
3	0.80	0.05	2	-	2	1080*	2	1965	28
1	0.85	0.05	1	-	1	1080*	1	1961	29
33	0.80	0.15	22	4	18	1080*	19	1966 GAS SOLD TO TRANS-CANADA	30
62	0.80	0.10	44	1	43	1080*	46	1965 PIPE LINES LIMITED	31
36	0.85	0.15	26	-	26	1080*	28	1966	32
4	0.80	0.15	3	-	3	1080*	3	1967	33
230	0.85	0.10	180	22	158	1080*	171	1967	34
75	0.80	0.04	58	3	55	1080*	59	1968	35
19	0.80	0.04	15	9	6	1080*	6	1968	36
86	0.80	0.04	66	3	63	1080*	68	1968	37
8	0.80	0.04	6	-	6	1080*	6	1968	38
18	0.75	0.04	13	-	13	1080*	14	1968	39
260	0.85	0.05	210	61	149	1080*	161	1968	40
150	0.85	0.05	120	32	88	1080*	95	1968	41
16	0.85	0.05	13	-	13	1080*	14	1968	42
17	0.85	0.05	13	-	13	1080*	14	1968	43
7	0.90	0.20	5	-	5	1170	6	1961	44
									45
16	0.80	0.10	12	-	12	1040	12	1966	46
									47
6	0.80	0.05	4	-	4	1140	5	1965 GAS SOLD TO NORTHWESTERN	48
16	0.65	0.15	9	1	8	1250	10	1966 UTILITIES LIMITED	49

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	GOLD CREEK										
2	CADOMIN										
3	WABAMUN A	1964	10,880	0.994	5150	214	9,400	64	0.07	0.15	1.00
4	WABAMUN B	1964	10,900	0.994	5150	214	1,100	122	0.07	0.15	1.00
5	GOLDEN SPIKE										
6	VIKING										
7	BLAIRMORE										
8	D-1 A	1949	4,440	0.681	1580	127	1,260	53	0.09	0.20	0.82
9	D-2 ASSOC										
10	D-2 SOLN										
11	D-2 A ASSOC										
12	D-3 A SOLN	1949	5,650								
13	GOODWIN										
14	MANNVILLE										
15	JURASSIC A	1956	5,900	0.661	2010	160	4,560	13	0.20	0.30	0.86
16	GORDONDALE										
17	PEACE RIVER A	1952	2,740	0.565	620	90	9,190	15	0.19	0.30	0.93
18	PEACE RIVER (OTHER)										
19	GETHING A	1953	4,240	0.596	1470	107	7,850	11	0.12	0.30	0.85
20	GETHING (OTHER)										
21	GREENCOURT										
22	JURASSIC A	1961	4,720	0.658	1610	128	11,580	12	0.13	0.60	0.83
23	PEKISKO A	1961	4,880	0.660	1630	130	7,100	29	0.12	0.25	0.83
24	PEKISKO (OTHER)										
25	HACKETT										
26	MANNVILLE A	1952	3,840	0.650	3420	135	1,220	105	0.18	0.30	0.85
27	MANNVILLE (OTHER)										
28	HAIRY HILL										
29	VIKING										
30	COLONY A	1954	1,790	0.601	630	68	3,220	21	0.24	0.30	0.91
31	MANNVILLE (OTHER)										
32	NISKU										
33	HALLIDAY										
34	VIKING										
35	HAMELIN CREEK										
36	CADOTTE										
37	GETHING										
38	CADOMIN A	1951	3,310	0.610	1410	118	3,980	11	0.16	0.30	0.87
39	TRIASSIC										
40	HAMILTON LAKE										
41	VIKING										
42	VIKING ASSOC										
43	MANNVILLE										
44	HANNA										
45	VIKING										
46	MANNVILLE										
47	BANFF										
48	HARMATTAN EAST										
49	RUNDLE ASSOC	1954	8,390	0.729	3400	190	47,700	31	0.10	0.20	0.83
50	RUNDLE SOLN	1957	8,620								

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
10	0.85	0.15	7	-	7	1110*	8	1966		2
410	0.80	0.30	230	-	230	1040*	239	1967		3
92	0.80	0.30	51	-	51	1040*	53	1966		4
										5
8	0.80	0.05	6	1	5	1050	5	1965	GAS INJECTED INTO D-3 ZONE	6
14	0.80	0.05	11	1	10	1050	11	1968		7
25	0.90	0.10	20	12	8	1060	8	1955		8
3	0.85	0.15	3	-	3	1120	3	1966		9
7	0.65	0.20	3	1	2	1120*	2	1965		10
-	0.90	0.10	-	-43	43	1100*	47	1968		11
130	0.90	0.40	69	20	49	1130*	55	1966		12
										13
1	0.75	0.10	1	-	1	1050	1	1964		14
20	0.85	0.10	15	-	15	1070	16	1964		15
										16
34	0.85	0.05	27	24	3	1000	3	1962	GAS SOLD TO WESTCOAST	17
1	0.85	0.05	1	-	1	1000	1	1962	TRANSMISSION COMPANY	18
39	0.85	0.05	29	21	8	1020	8	1962	LIMITED	19
17	0.85	0.05	14	8	6	1020	6	1965		
										20
35	0.80	0.10	25	-	25	1070	27	1968		21
92	0.85	0.10	70	-	70	1130	79	1968		22
2	0.80	0.05	2	-	2	1130	2	1968		24
										25
60	0.90	0.10	49	7	42	1100	46	1963	GAS SOLD TO TRANS-	26
2	0.90	0.10	1	-	1	1100	1	1963	CANADA PIPE LINES	27
									LIMITED	
										28
2	0.75	0.05	1	-	1	980	1	1961		29
22	0.90	0.05	19	12	7	1000*	7	1961	GAS SOLD TO WESTERN	30
1	0.85	0.05	1	-	1	1000*	1	1966	MINERALS LIMITED	31
3	0.80	0.05	2	-	2	1000	2	1966		32
										33
5	0.80	0.05	4	1	3	1040	3	1961	GAS SOLD TO TRANS-CANADA	34
									PIPE LINES LIMITED	
										35
3	0.80	0.05	2	-	2	1000	2	1962		36
3	0.85	0.05	3	-	3	1010	3	1961		37
21	0.85	0.05	17	5	12	1060	13	1962	SUPPLIES LOCAL UTILITY	38
2	0.75	0.05	1	-	1	1160	1	1961		39
										40
34	0.75	0.05	24	-	24	1040	25	1967		41
7	0.65	0.05	4	-	4	1040	4	1967		42
7	0.90	0.05	6	-	6	1050	6	1964		43
										44
10	0.85	0.05	8	-	8	1040	8	1966		45
3	0.85	0.05	2	-	2	1050	2	1957		46
2	0.80	0.05	1	-	1	1080	1	1957	SUPPLIES LOCAL UTILITY	47
										48
1180	0.90	0.15	900	-13	913	1080*	986	1964	RESERVOIR BEING CYCLED	49
170	0.55	0.25	71	13	58	1080*	63	1966	GAS INJECTED INTO GAS CAP	50

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DISCOVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESSIBILITY FACTOR FRACTION
1	Harmattan Elkton										
2	Blairmore										
3	Rundle A	1957	9,150	0.709	3630	205	2,740	35	0.08	0.20	0.89
4	Rundle B Assoc	1955	8,960	0.819	3430	196	7,140	6	0.09	0.20	0.85
5	Rundle C Assoc	1954	8,990	0.840	3630	200	19,020	70	0.11	0.20	0.84
6	Rundle C Soln	1955	9,130								
7	D-3 A	1961	11,000	0.931	4680	230	13,970	67	0.05	0.10	0.75
8	Heart River										
9	Cadotte										
10	Notikewin										
11	Hercules										
12	Viking										
13	Mannville 30-50-22	1960	3,980	0.600	1250	102	500	57	0.20	0.35	0.86
14	Mannville (Other)										
15	High Prairie										
16	Cadotte										
17	Notikewin										
18	Gething										
19	Holburn										
20	Cardium										
21	Mannville										
22	Holmberg										
23	Mannville A	1952	3,420	0.700	1100	94	2,100	13	0.20	0.30	0.81
24	Mannville (Other)										
25	Homeglen-Rimbey										
26	D-3 Assoc	1953	7,840	0.703	2830	179	12,800	173	0.07	0.10	0.85
27	D-3 Soln	1953	7,920								
28	Hunter Valley										
29	Rundle A	1962	9,280	0.680	3580	147	1,570	83	0.07	0.20	0.84
30	Rundle (Other)										
31	Hussar										
32	Belly River										
33	Viking E	1961	3,740	0.626	1150	100	13,590	4	0.20	0.30	0.89
34	Viking (Other)										
35	Viking B Assoc	1955	4,040	0.626	1120	104	13,000	5	0.20	0.30	0.88
36	Basal Colorado A	1952	4,330	0.606	1240	110	16,390	3	0.17	0.30	0.88
37	Basal Colorado C	1955	4,120	0.627	1230	112	16,080	4	0.18	0.30	0.88
38	BSL COL (Other)										
39	Glauconitic N	1955	4,470	0.641	1470	110	12,460	14	0.21	0.30	0.83
40	Glauconitic R	1960	4,650	0.641	1490	110	500	26	0.21	0.30	0.83
41	GLC A Assoc	1952	4,690	0.641	1480	110	5,290	17	0.22	0.25	0.83
42	GLC B Assoc	1956	4,700	0.669	1470	112	3,900	7	0.20	0.30	0.83
43	Glauconitic A Soln	1957	4,650								
44	Ostracod R	1956	4,660	0.649	1510	114	7,480	5	0.20	0.35	0.82
45	Ostracod F Assoc	1956	4,570	0.654	1370	111	8,300	5	0.21	0.25	0.84
46	Basal Mannville B	1960	4,330	0.668	1470	107	1,330	45	0.15	0.30	0.82
47	Basal Mannville D	1955	4,820	0.660	1510	115	530	38	0.16	0.30	0.83
48	Mannville (Other)										
49	MANN Assoc (Other)										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
3	0.90	0.05	2	-	2	1020	2	1966		2
55	0.85	0.15	40	3	37	1100	41	1964	Gas sold to TCPL	3
28	0.85	0.15	21	8	13	1080*	14	1964	Gas injected into gas cap	4
1150	0.90	0.15	880	-36	916	1080*	989	1964	Reservoir being cycled	5
180	0.65	0.30	83	28	55	1080*	59	1966	Injected into gas cap	6
600	0.80	0.65	170	6	164	960	157	1967	Sold to Alberta and Southern Gas Co. Ltd.	7
										8
2	0.85	0.05	2	1	1	1000	1	1964	Supplies Local Utility	9
2	0.90	0.05	2	-	2	1000	2	1964		10
										11
20	0.85	0.05	17	-	17	1050	18	1955		12
15	0.90	0.05	13	-	13	960	12	1961		13
20	0.80	0.05	15	-	15	960	14	1966	Gas sold to Northwestern Utilities Limited	14
										15
3	0.85	0.05	3	-	3	1000	3	1961	Presently considered	16
8	0.85	0.05	6	-	6	1100	7	1961	beyond economic reach	17
2	0.85	0.05	1	-	1	1000	1	1961		18
										19
8	0.80	0.05	6	3	3	980	3	1966	Gas injected into Golden	20
16	0.85	0.10	12	-	12	1120	13	1968	Spike	21
										22
15	0.85	0.05	12	-	12	1050	13	1960	Gas sold to Baroid of	23
11	0.85	0.05	9	-	9	1050	9	1958	Canada Ltd. Plant	24
										25
1170	0.75	0.15	760 >	240**	557	1020*	568	1964	Gas sold to Trans-Canada	26
86	0.50	0.15	37					1964	Pipe Lines Limited and Alberta and Southern Gas Co. Ltd.	27
										28
73	0.85	0.25	47	-	47	1000	47	1964		29
5	0.85	0.25	3	-	3	1000	3	1964		30
										31
4	0.75	0.05	3	2	1	1000	1	1961	Gas sold to Trans-Canada	32
24	0.80	0.05	18	4	14	1020*	14	1966	Pipe Lines Limited	33
17	0.80	0.05	13	3	10	1020*	10	1961		34
32	0.75	0.05	22	3	19	1020*	19	1961		35
26	0.75	0.05	19	7	12	1020*	12	1961		36
26	0.75	0.05	19	8	11	1030*	11	1964		37
4	0.80	0.05	3	-	3	1030*	3	1965		38
120	0.85	0.05	100	41	59	1030*	61	1967		39
20	0.85	0.05	16	9	7	1030*	7	1967		40
75	0.85	0.05	61	32	29	1030*	30	1967		41
19	0.85	0.05	15	9	6	1030*	6	1967		42
20	0.65	0.25	10	-	10	1030*	10	1967		43
26	0.85	0.05	21	1	20	1030*	21	1965		44
27	0.80	0.05	20	1	19	1030*	20	1964		45
30	0.85	0.05	25	-	25	1030*	26	1963		46
11	0.90	0.05	10	1	9	1030*	9	1961		47
120	0.85	0.05	99	18	81	1030*	83	1967		48
32	0.85	0.05	25	2	23	1030*	24	1967		49

TABLE 1A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DISCOVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESSIBILITY FACTOR FRACTION
1	Inland										
2	Viking A	1961	2,190	0.608	850	74	15,990	3	0.20	0.30	0.89
3	Innisfail										
4	Blairmore Assoc										
5	Rundle										
6	Wabamun										
7	D-3 Assoc	1957	8,440	0.808	3550	94	1,220	28	0.06	0.15	0.84
8	D-3 Soln	1957	8,580								
9	Jarvie										
10	Viking										
11	Mannville										
12	Jenner										
13	Bow Island										
14	Basal Colorado										
15	Mannville										
16	Mannville Assoc										
17	Pekisko										
18	Joarcam										
19	Viking										
20	Viking Assoc										
21	Joffre										
22	Viking										
23	Blairmore										
24	Leduc Assoc										
25	Judy Creek										
26	Viking A	1959	4,610	0.630	1290	132	23,320	5	0.18	0.35	0.88
27	BH Lk A Soln	1959	8,660								
28	BH Lk B Soln	1959	8,840								
29	Judy Creek South										
30	Rundle A	1960	6,040	0.626	1900	155	500	56	0.10	0.20	0.86
31	Jumping Pound										
32	Mississippian	1944	9,590	0.706	3980	195	7,090	141	0.08	0.10	0.90
33	Jumping Pound West										
34	Rundle A	1961	10,950	0.737	4250	185	9,952	136	0.07	0.15	0.92
35	Rundle B	1963	11,950	0.753	4320	190	3,570	130	0.07	0.15	0.93
36	Kaybob										
37	Notikewin A	1957	4,690	0.612	1530	134	25,650	13	0.20	0.35	0.88
38	Notikewin B	1958	4,820	0.609	1420	133	27,710	10	0.16	0.35	0.88
39	Notikewin D	1959	5,050	0.609	1390	145	5,660	6	0.19	0.35	0.88
40	Notikewin (Other)										
41	Spirit River										
42	Gething										
43	Cadomin										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
21	0.75	0.05	15	-	15	980	15	1963 Presently considered beyond economic reach	2
									3
1	0.80	0.15	1	-	1	1050	1	1965	4
22	0.90	0.10	18	-	18	1080	19	1961	5
3	0.85	0.15	2	-	2	1080	2	1961	6
17	0.90	0.35	10	-	10	1020	10	1961	7
200	0.55	0.45	60	17	43	1130*	49	1965 Gas sold to Trans-Canada Pipe Lines Limited	8
									9
10	0.80	0.05	7	-	7	1040	7	1960 Presently considered	10
9	0.85	0.05	8	-	8	1100	9	1956 beyond economic reach	11
									12
5	0.75	0.05	3	-	3	990	3	1961	13
6	0.80	0.05	5	-	5	1040	5	1961	14
18	0.80	0.05	14	-	14	1050	15	1961	15
8	0.80	0.05	6	-	6	1050	6	1966	16
3	0.85	0.05	2	-	2	1000	2	1965	17
									18
3	0.75	0.05	2	-	2	1040	2	1963	19
70	0.75	0.05	50	-	50	1040	52	1963	20
									21
1	0.75	0.10	1	-	1	1000	1	1967	22
41	0.85	0.10	32	-	32	1020	33	1967	23
2	0.85	0.15	2	-	2	1050	2	1967	24
									25
54	0.80	0.05	41	2	39	1010	39	1968 Gas sold to Northwestern	26
560	0.45	0.30	180	16	164	1090*	179	1966 Utilities, Limited and	27
270	0.50	0.30	93	7	86	1090*	94	1966 Alberta and Southern Gas Co. Ltd.	28
									29
13	0.90	0.10	10	-	10	1050*	11	1960 Presently considered beyond economic reach	30
									31
780	0.85	0.15	560	261	299	1050*	314	1964 Gas sold to Canadian Western Natural Gas Company Limited	32
									33
830	0.80	0.20	530	4	526	1050*	552	1968 Gas sold to Canadian	34
270	0.80	0.20	170	1	169	1050*	178	1968 Western Natural Gas Company Limited	35
									36
200	0.85	0.05	160	20	140	1100*	154	1967 Gas sold to Alberta and	37
120	0.85	0.05	98	47	51	1100*	56	1966 Southern Gas Co. Ltd	38
17	0.85	0.05	14	-	14	1100*	15	1966	39
6	0.85	0.05	5	-	5	1100*	6	1966	40
8	0.85	0.05	6	-	6	1000	6	1964	41
16	0.85	0.05	13	-	13	1050	14	1964	42
48	0.85	0.05	38	-	38	1040	40	1964	43

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	Kaybob (continued)										
2	Cadomin B Assoc	1962	5,800	0.719	2210	160	6,110	17	0.16	0.30	0.84
3	Wabamun A										
4	Nisku										
5	Beaverhill Lake C										
6	BH Lk Assoc										
7	BH Lk A Soln	1957	9,780								
8	Kaybob South										
9	Viking A	1960	5,710	0.657	1460	150	30,350	2	0.14	0.40	0.86
10	Cadomin A	1961	6,710	0.644	2230	181	8,390	8	0.15	0.35	0.87
11	Cadomin B	1961	6,750	0.639	2230	181	3,430	13	0.15	0.35	0.87
12	Cadomin C	1961	6,750	0.639	2230	181	3,122	9	0.15	0.35	0.87
13	Cadomin (Other)										
14	Triassic										
15	Triassic Assoc										
16	Triassic Soln	1962	6,980								
17	Nisku A	1958	9,510	0.795	4100	225	1,100	4	0.05	0.20	0.93
18	Nisku (Other)										
19	Beaverhill Lake A	1961	10,560	0.823	4700	238	26,600	48	0.09	0.15	0.91
20	Killam										
21	Viking										
22	Mannville										
23	Killam North										
24	Mannville										
25	Mannville Assoc										
26	Knappen										
27	Mannville										
28	Sunburst-Swift										
29	Sawtooth										
30	Mississippian										
31	Knopcik										
32	Doe Creek A	1964	2,920	0.664	900	102	4,360	9	0.22	0.30	0.87
33	Paddy										
34	Lac La Biche										
35	Mannville										
36	Lambert Creek										
37	Wabamun 4-51-21	1957	12,870	0.792	5500	250	1,100	48	0.03	0.20	1.05
38	Leahurst										
39	Mannville A	1950	4,150	0.668	1490	128	3,660	18	0.15	0.30	0.83
40	Mannville (Other)										
41	Leduc-Woodbend										
42	Cardium										
43	Viking										
44	Blairmore										
45	Blairmore Assoc										
46	D-1 Assoc										
47	D-2 Assoc	1947	4,780	0.733	1780	150	9,770	41	0.02	0.20	0.80
48	D-2 A Soln	1947	5,100								
49	D-2 B Soln	1947	5,260								
50	D-3 A Assoc	1947	5,300	0.655	1890	152	17,490	60	0.08	0.15	0.83
51	D-3 Assoc (Other)										
52	D-3 A Soln	1947	5,320								
53	D-3 Soln (Other)										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
76	0.85	0.05	62	-	62	1040	64	1964	2
1	0.80	0.10	1	-	1	1070	1	1961	3
5	0.85	0.35	3	-	3	1070	3	1961	4
1	0.80	0.15	1	-	1	1070	1	1964	5
6	0.80	0.15	4	-	4	1140*	5	1962	6
340	0.40	0.25	100	11	89	1140*	101	1965	7
									8
22	0.75	0.05	16	-	16	1120	18	1966	9
39	0.80	0.05	30	-	30	1070*	32	1966	10
27	0.80	0.05	20	-	20	1070*	21	1966	11
17	0.80	0.05	13	-	13	1070*	14	1966	12
8	0.75	0.05	6	-	6	1070*	6	1967	13
3	0.80	0.05	2	-	2	1160*	2	1964	14
2	0.80	0.05	2	-	2	1160*	2	1963	15
100	0.40	0.25	30	-	30	1160*	35	1965	16
19	0.90	0.20	14	-	14	1160*	16	1963	17
1	0.80	0.05	1	-	1	1160*	1	1958	18
1180	0.85	0.30	700	-	700	1090*	763	1968	19
									20
2	0.80	0.05	2	-	2	1010	2	1967	21
12	0.80	0.05	9	-	9	1000	9	1967	22
									23
19	0.80	0.05	15	-	15	1000	15	1966 Supplies local Utility	24
5	0.80	0.05	4	-	4	1000	4	1966	25
									26
4	0.80	0.05	2	-	2	1000	2	1966 Gas sold to Canadian	27
3	0.85	0.05	2	-	2	1000	2	1965 Montana Gas Company	28
8	0.80	0.05	6	-	6	1000	6	1967 Limited	29
7	0.90	0.10	6	-	6	1000	6	1965	30
									31
18	0.75	0.05	12	-	12	1000	12	1966 Supplies local Utility	32
1	0.80	0.05	1	-	1	1020	1	1964	33
									34
10	0.80	0.05	8	1	7	1010	7	1968 Supplies local Utility	35
									36
14	0.75	0.05	10	-	10	1050	11	1958 Presently considered beyond economic reach	37
									38
33	0.85	0.05	26	2	24	1160*	28	1965 Supplies local Utility	39
10	0.85	0.05	8	-	8	1160*	9	1962	40
									41
12	0.80	0.05	9	6	3	1040	3	1967 Injected into Nisku and	42
20	0.80	0.05	15	3	12	1070	13	1959 Leduc Gas Cap	43
27	0.85	0.05	21	16	5	1180	6	1959	44
57	0.85	0.05	45	6	39	1180	46	1961	45
4	0.85	0.10	3	2	1	1050	1	1966	46
37	0.90	0.15	28	-12	40	1180	47	1958	47
130	0.75	0.30	70	61	9	1180	11	1965 Gas sold to Northwestern	48
41	0.75	0.30	21	15	6	1180	7	1965 Utilities Limited	49
420	0.85	0.15	300	-23	323	1180	381	1964	50
6	0.85	0.15	4	1	3	1180	4	1964	51
140	0.70	0.30	70	68	2	1180	2	1966	52
8	0.70	0.30	4	3	1	1180	1	1966	53

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	LEGAL										
2	MANNVILLE										
3	LINDBERGH										
4	VIKING										
5	MANNVILLE										
6	LITTLE BOW										
7	U MANN A	1965	3,950	0.669	1680	106	3,440	8	0.21	0.40	0.82
8	MANNVILLE (OTHER)										
9	MANN ASSOC										
10	LLOYDMINSTER										
11	MANNVILLE										
12	LONE PINE CREEK										
13	MANNVILLE										
14	WABAMUN A	1955	7,850	0.758	3570	180	21,300	33	0.05	0.20	0.89
15	D-3 A ASSOC	1963	7,990	0.814	3260	174	2,420	47	0.08	0.15	0.84
16	D-3 A SOLN	1963	8,010								
17	D-3 ASSOC (OTHER)										
18	LONG COULEE										
19	MANNVILLE A	1965	4,380	0.832	1880	105	2,070	9	0.20	0.35	0.78
20	MANNVILLE (OTHER)										
21	LOOKOUT BUTTE										
22	RUNDLE A	1959	12,060	0.724	4770	190	7,280	153	0.07	0.20	0.96
23	LOVETT RIVER										
24	BLAIRMORE 2-47-19	1959	10,010	0.615	4300	190	1,100	9	0.15	0.25	0.96
25	RUNDLE A	1957	11,870	0.612	4950	220	1,100	177	0.06	0.20	1.01
26	MAJEAU LAKE										
27	MANNVILLE										
28	MISSISSIPPIAN	1951	4,250	0.673	1500	123	500	60	0.09	0.15	0.82
29	MALMO										
30	VIKING										
31	BLAIRMORE										
32	BLAIRMORE ASSOC										
33	NISKU ASSOC										
34	D-3 B	1959	5,990	0.757	2180	128	1,960	46	0.07	0.10	0.81
35	D-3 ASSOC										
36	MANYBERRIES										
37	BOW ISLAND A	1947	2,570		GIP BASED ON MATERIAL BALANCE						
38	BOW ISLAND (OTHER)										
39	MARLBORO										
40	LEDUC A	1965	12,140	0.738	4960	250	500	173	0.07	0.10	0.96
41	MARSH HEAD CREEK										
42	LEDUC 17-59-20	1961	11,540	0.659	4800	245	500	29	0.06	0.15	0.92

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
6	0.75	0.05	4	2	2	1030	2	1955 Gas sold to Canadian Industrial Gas and Oil Limited	2
4	0.65	0.05	2	-	2	990	2	1961	4
23	0.80	0.05	17	7	10	1000	10	1961 Supplies salt Plant	5
20	0.85	0.05	16	1	15	1000	15	1968	7
17	0.85	0.05	14	-	14	1000	14	1968 Gas sold to Trans-Canada	8
1	0.85	0.05	1	-	1	1000	1	1968 Pipe Lines Limited	9
24	0.85	0.30	14	12	2	950	2	1966 Supplies Local Utility	11
5	0.85	0.10	4	-	4	1020	4	1963	13
280	0.85	0.20	190	6	184	1000	184	1967 Gas sold to Trans-Canada	14
77	0.85	0.25	48	> 1**	52	1060*	55	1967 Pipe Lines Limited	15
10	0.65	0.30	5					1967	16
9	0.85	0.20	6	-	6	1060*	6	1967	17
16	0.85	0.25	10	-	10	1000	10	1968 Gas sold to Trans-Canada	19
9	0.85	0.20	6	-	6	1000	6	Pipe Lines Limited	20
660	0.80	0.15	450	9	441	1060*	468	1967 Gas sold to Trans-Canada Pipe Lines Limited	22
12	0.90	0.05	10	-	10	1040	10	1959	24
97	0.80	0.10	70	-	70	1040	73	1959	25
2	0.80	0.05	2	-	2	1000	2	1955 Presently considered	27
12	0.90	0.10	10	-	10	1070	11	1955 beyond economic reach	28
8	0.85	0.05	6	-	6	1000	6	1960	30
8	0.85	0.10	6	-	6	1030	6	1959	31
2	0.70	0.15	1	-	1	1030	1	1960	32
4	0.80	0.20	3	-	3	1100	3	1959	33
42	0.85	0.20	29	-	29	1100	32	1966	34
2	0.85	0.15	1	-	1	1100	1	1966	35
28	0.80	0.02	25	22	3	940	3	1967 Gas sold to Canadian	37
5	0.65	0.02	3	-	3	940	3	1967 Montana Gas Company Limited	38
63	0.85	0.25	40	-	40	1000	40	1966	40
27	0.85	0.35	15	-	15	1050	16	1964 Presently considered beyond economic reach	42

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DISCOVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESSIBILITY FACTOR FRACTION
1	MARTEN HILLS										
2	PELICAN										
3	GRAND RAPIDS										
4	WABISKAW A	1961	2,250	0.572	390	80	173,500	18	0.29	0.30	0.95
5	WABISKAW (OTHER)										
6	WABAMUN A	1961	2,260	0.572	390	82	92,590	40	0.15	0.40	0.95
7	WABAMUN (OTHER)										
8	MAZEPPA										
9	MISS 16-19-27	1956	6,800	0.709	2700	143	1,100	33	0.08	0.20	0.81
10	MEDICINE HAT										
11	MEDICINE HAT	1904	1,600	0.574	625	62	983,680	8	0.26	0.40	0.91
12	BOW ISLAND										
13	SAWTOOTH A	1947	3,280	0.582	1500	105	10,160	4	0.20	0.30	0.86
14	MEDICINE RIVER										
15	GLAUCONITIC										
16	GLAUCONITIC ASSOC										
17	GLAUCONITIC SOLN										
18	OSTRACOD										
19	OSTRACOD B ASSOC	1954	7,010	0.764	2830	155	3,980	5	0.13	0.35	0.80
20	OSTRACOD C ASSOC	1960	7,480	0.764	2930	155	2,900	14	0.14	0.25	0.79
21	OST ASSOC (OTHER)										
22	OSTRACOD SOLN										
23	BASAL QUARTZ										
24	BSL QTZ B ASSOC	1959	7,000	0.716	2380	150	2,310	19	0.14	0.30	0.81
25	BSL QTZ ASSOC (OTHER)										
26	BASAL QUARTZ SOLN										
27	BASAL MANNVILLE A	1958	7,660	0.710	2,640	160	3,680	12	0.14	0.30	0.81
28	BSL MANN (OTHER)										
29	JURASSIC										
30	JURASSIC D ASSOC	1962	6,970	0.699	2340	145	910	22	0.15	0.30	0.81
31	JURASSIC ASSOC (OTHER)										
32	JURASSIC SOLN										
33	RUNDLE										
34	RUNDLE ASSOC										
35	RUNDLE SOLN										
36	LEDUC ASSOC										
37	MILLET										
38	MANNVILLE 1-49-25	1951	4,440	0.696	1510	130	4,700	6	0.18	0.35	0.83
39	MANNVILLE (OTHER)										
40	MINNEHIK-BUCK LAKE										
41	BLAIRMORE										
42	PEKISKO A	1952	6,910	0.707	2490	184	42,910	24	0.09	0.25	0.85
43	PEKISKO B	1961	7,300	0.707	2490	184	7,620	19	0.10	0.25	0.85
44	MITSUE										
45	MANNVILLE										
46	GILWOOD ASSOC										
47	GILWOOD A SOLN	1964	5,680								
48	MOOSE MOUNTAIN										
49	RUNDLE 6-23-6	1960	7,560	0.706	1940	140	2,000	130	0.06	0.20	0.82
50	MORINVILLE										
51	VIKING										
52	BLAIRMORE										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)			
INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/68 BCF	REMAINING MARKETABLE GAS MAY 31/68 BCF	GROSS HEATING VALUE BTU CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
2	0.65	0.05	1	-	1	990	1	1964		2
10	0.70	0.05	6	-	6	990	6	1967		3
770	0.75	0.05	550	-	550	990	544	1968		4
13	0.75	0.05	9	-	9	990	9	1967		5
380	0.75	0.05	270	-	270	1000	270	1968		6
10	0.75	0.05	7	-	7	1000	7	1967		7
										8
20	0.90	0.15	15	-	15	1060	16	1957	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH	9
										10
2550	0.80	0.02	2000	543	1457	970	1414	1967	GAS SOLD TO TRANS-CANADA	11
15	0.60	0.05	9	1	8	970	8	1964	PIPE-LINE LIMITED, MANY	12
25	0.85	0.05	20	2	18	1000	18	1963	ISLANDS PIPE LINES LIMITED AND SUPPLIES. LOCAL UTILITY	13
										14
7	0.90	0.15	6	-	6	1150*	7	1968	GAS SOLD TO TRANS-CANADA	15
4	0.85	0.15	3	-	3	1150*	3	1968	PIPE LINE LIMITED	16
14	0.60	0.45	5	-	5	1150*	6	1968		17
12	0.85	0.15	8	-	8	1150*	9	1968		18
14	0.85	0.15	10	-	10	1150*	12	1968		19
40	0.85	0.15	29	1	28	1150*	32	1968		20
7	0.85	0.15	5	-	5	1150*	6	1968		21
7	0.60	0.45	2	-	2	1150*	2	1968		22
32	0.85	0.15	23	-	23	1150*	26	1968		23
32	0.85	0.15	23	-	23	1150*	26	1968		24
19	0.85	0.15	14	-	14	1150*	16	1968		25
22	0.40	0.45	5	-	5	1150*	6	1968		26
34	0.85	0.15	25	-	25	1150*	29	1968		27
9	0.85	0.15	7	-	7	1150*	8	1968		28
15	0.85	0.15	11	-	11	1020*	11	1968		29
15	0.80	0.15	10	-	10	1020*	10	1968		30
16	0.80	0.15	11	-	11	1020*	11	1968		31
70	0.65	0.45	25	-	25	1020*	26	1968		32
20	0.85	0.15	14	1	13	1100*	14	1968		33
9	0.85	0.15	6	-	6	1100*	7	1968		34
36	0.60	0.45	12	-	12	1200*	14	1968		35
2	0.85	0.20	1	-	1	1100*	1	1968		36
										37
17	0.80	0.10	12	-	12	1020	12	1957	PRESENTLY CONSIDERED	38
5	0.80	0.10	3	-	3	1020	3	1957	BEYOND ECONOMIC REACH	39
										40
6	0.80	0.05	4	-	4	1000	4	1959		41
500	0.85	0.07	400	96	304	1120*	340	1966	GAS SOLD TO ALBERTA AND	42
71	0.85	0.10	54	-	54	1120*	60	1966	SOUTHERN GAS CO. LTD.	43
										44
2	0.80	0.05	1	-	1	1070	1	1968		45
3	0.90	0.25	2	-	2	1170	2	1966		46
390	0.55	0.25	160	-	160	1170	187	1965		47
										48
75	0.80	0.25	45	-	45	1000	45	1964		49
										50
4	0.75	0.05	3	-	3	1000	3	1962		51
140	0.80	0.10	99	43	56	1070*	60	1962	GAS SOLD TO CANADIAN INDUSTRIAL GAS AND OIL LIMITED AND SUPPLIES LOCAL UTILITY	52

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DIS-COVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESS-IBILITY FACTOR FRACTION
1	Mountain Park										
2	Triassic 36-47-22	1956	10,100	0.617	3880	237	1,100	28	0.15	0.30	0.96
3	Muriel Lake										
4	Mannville										
5	Nevis										
6	Blairmore A	1952	4,750	0.662	1400	131	11,990	7	0.22	0.20	0.84
7	Blairmore (Other)										
8	Devonian	1952	5,580	0.687	2340	141	31,000	75	0.07	0.15	0.81
9	New Norway										
10	Viking										
11	Blairmore										
12	Nipisi										
13	Gilwood A Soln	1965	5,610								
14	Niton										
15	Blairmore										
16	Cadomin										
17	Nordegg										
18	Triasstc										
19	Rundle 17-41-17	1960	4,930	0.575	1840	126	2,130	70	0.04	0.20	0.86
20	Normandville										
21	Peace River										
22	Gething										
23	Triassic										
24	Belloy										
25	Mississippian A	1956	3,440	0.637	1570	100	1,410	13	0.27	0.35	0.83
26	Miss (Other)										
27	Obed										
28	Viking 26-55-22	1967	8,080	0.618	3830	166	1,100	15	0.14	0.40	0.92
29	Blairmore 36-54-23	1966	9,430	0.669	4000	237	500	29	0.15	0.35	0.98
30	Rundle										
31	Nisku 13-54-23	1964	12,990	0.784	5580	270	1,100	65	0.07	0.20	0.98
32	Nisku 23-54-23	1965	13,120	0,781	5580	270	1,100	82	0.07	0.20	0.98
33	Oberlin										
34	Mannville										
35	Okotoks										
36	Crossfield	1951	8,710	0.898	3600	175	21,990	39	0.06	0.20	0.70
37	Olds										
38	Wabamun A Assoc	1952	8,680	0.753	3590	165	31,500	30	0.05	0.20	0.83
39	Wabamun B "	1959	8,600	0.753	3600	165	1,100	69	0.05	0.20	0.83
40	Wabamun A Soln	1965	8,990								
41	Owlseye										
42	Mannville										
43	Oyen										
44	Viking A	1942	2,570	0.577	970	85	6,750	10	0.24	0.30	0.89
45	Viking (Other)										
46	Detrital										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
29	0.90	0.05	25	-	25	1090	27	1956 PRESENTLY CONSIDERED BEYOND ECONOMIC REACH	2
									3
9	0.75	0.05	6	1	5	1000	5	1964 SUPPLIES LOCAL UTILITY	4
									5
64	0.85	0.10	49	-	49	1000	49	1959	6
2	0.85	0.10	1		1	1000	1	1964	7
1060	0.90	0.15	810	163	647	1000*	647	1967 GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED	8
									9
3	0.80	0.10	2	-	2	1000	2	1959	10
10	0.85	0.05	9	-	9	1010	9	1959	11
									12
250	0.55	0.25	110		110	1150	127	1965 PRESENTLY CONSIDERED BEYOND ECONOMIC REACH	13
									14
13	0.80	0.05	10	-	10	1070	11	1966	15
8	0.90	0.05	7	-	7	1070	7	1963	16
									17
9	0.90	0.10	7		7	1000	7	1961 PRESENTLY CONSIDERED	18
25	0.90	0.10	20		20	1000	20	1961 BEYOND ECONOMIC REACH	19
									20
1	0.70	0.05	1	-	1	990	1	1967	21
6	0.85	0.05	5		5	980	5	1967	22
1	0.85	0.05	1	-	1	1090	1	1967	23
2	0.85	0.05	2	-	2	1060	2	1967	24
16	0.85	0.05	13	2	11	1050	12	1967 SUPPLIES LOCAL UTILITY	25
22	0.85	0.05	18	1	17	1050	18	1967	26
									27
14	0.85	0.05	12	-	12	1020	12	1967 PRESENTLY CONSIDERED	28
13	0.85	0.05	11	-	11	1040	11	1966 BEYOND ECONOMIC REACH	29
4	0.85	0.10	4	-	4	1050	4	1966	30
48	0.85	0.35	27	-	27	1060	29	1966	31
67	0.85	0.35	34		34	1060	36	1966	32
									33
3	0.70	0.05	2	2	< 1	1090	< 1	1967 SUPPLIES LOCAL UTILITY	34
									35
470	0.80	0.55	170	46	124	1000	124	1966 GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED	36
									37
390	0.85	0.25	250	36	214	1000*	214	1967 GAS SOLD TO TRANS-	38
31	0.85	0.25	20	-	20	1000*	20	1967 CANADA PIPE LINES LIMITED	39
62	0.65	0.40	24	-	24	1000*	24	1967	40
									41
2	0.85	0.05	2	-	2	1020	2	1961 SUPPLIES LOCAL UTILITY	42
									43
36	0.85	0.05	29	4	25	980	25	1965 GAS SOLD TO TRANS-	44
8	0.80	0.05	6	4	2	980	2	1965 CANADA PIPE LINES LIMITED	45
11	0.85	0.05	9	1	8	1010	8	1965	46

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	PADDLE RIVER										
2	JURASSIC-DETRITAL	1956	5,050	0.695	1780	140	30,190	21	0.14	0.65	0.82
3	RUNDLE	1956	5,090	0.816	1780	130	9,300	14	0.08	0.35	0.81
4	PAKOWKI LAKE										
5	BOW ISLAND A	1955	2,200	0.590	790	75	21,480	3	0.21	0.30	0.91
6	BOW ISLAND (OTHER)										
7	MANNVILLE										
8	PARKLAND										
9	RUNDLE										
10	PARKLAND NORTH-EAST										
11	RUNDLE 29-15-26	1953	6,940	0.663	2830	145	2,130	16	0.07	0.25	0.83
12	RUNDLE (OTHER)										
13	PEMBINA										
14	KEYSTONE BR A	1957	3,180	0.595	1050	100	3,230	18	0.19	0.35	0.89
15	BELLY RIVER (OTHER)										
16	BELLY RIVER ASSOC										
17	BELLY RIVER SOLN										
18	CARDIUM SOLN	1953	5,080								
19	VIKING										
20	GLAUCONITIC A	1957	5,900	0.657	2000	160	11,240	26	0.15	0.45	0.82
21	GLAUCONITIC B	1960	5,760	0.667	2000	160	4,940	23	0.15	0.45	0.82
22	GLAUCONITIC C & D	1959	6,070	0.669	1980	160	3,330	25	0.15	0.45	0.82
23	MANNVILLE (OTHER)										
24	JURASSIC										
25	RUNDLE										
26	PENDANT D'OREILLE										
27	BOW ISLAND	1946	2,030	0.588	710	75	85,120	6	0.22	0.25	0.92
28	BOW ISLAND (OTHER)										
29	MANNVILLE A	1961	2,740	0.574	1150	85	4,480	20	0.21	0.35	0.87
30	MANNVILLE C	1965	2,690	0.572	1160	85	2,590	25	0.22	0.35	0.87
31	MANNVILLE (OTHER)										
32	PENHOLD										
33	VIKING 33-36-28	1958	5,590	0.685	1710	147	1,650	12	0.20	0.30	0.89
34	PHIL CAN										
35	GETHING										
36	MISSISSIPPIAN										
37	PINCHER CREEK										
38	RUNDLE A	1948	12,500	0.718	4940	191	14,000	310	0.04	0.20	0.97
39	PINE CREEK										
40	WABAMUN	1956	10,080	0.832	4500	210	9,650	26	0.07	0.15	0.82
41	WABAMUN (OTHER)										
42	D-3	1957	11,020	0.758	4580	235	9,480	122	0.07	0.15	0.91
43	PINE NORTHWEST										
44	D-3 A	1963	10,670	0.711	4650	240	5,110	138	0.06	0.10	0.95
45	PLAIN LAKE										
46	VIKING										
47	MANNVILLE 1-53-12	1952	2,180	0.578	750	73	3,430	9	0.25	0.25	0.90
48	MANNVILLE (OTHER)										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
170	0.80	0.10	130	12	118	1130*	133	1968 Gas sold to Northwestern	2
36	0.85	0.10	27	-	27	1060	29	1966 Utilities, Limited	3
									4
21	0.65	0.05	13	7	6	940	6	1967 Gas sold to Canadian	5
5	0.85	0.05	4	-	4	940	4	1967 Montana Gas Company	6
1	0.90	0.05	1	-	1	1000	1	1967 Limited	7
									8
3	0.85	0.15	2	2	0	1010	0	1963 Pool Abandoned	9
									10
15	0.85	0.15	11	-	11	1010	11	1963 Presently considered	11
5	0.90	0.15	4	-	4	1010	4	1956 beyond economic reach	12
									13
23	0.80	0.05	18	-	18	1070*	19	1965 Gas sold to Northwestern	14
33	0.80	0.05	26	2	24	1070*	26	1965 Utilities, Limited	15
25	0.80	0.05	19	-	19	1070*	20	1965	16
90	0.45	0.80	9	2	7	1070*	7	1965	17
4100	0.36	0.40	880	174	706	1130*	798	1967	18
11	0.80	0.05	8	-	8	1130*	9	1956	19
150	0.85	0.10	110	24	86	1130*	97	1966 Gas sold to Alberta and	20
57	0.85	0.10	44	5	39	1130*	44	1966 Southern Gas Co. Ltd.	21
41	0.85	0.10	31	-	31	1130*	35	1966	22
29	0.80	0.05	22	3	19	1130*	21	1959	23
18	0.85	0.05	15	-	15	1050*	16	1965	24
13	0.85	0.10	10	-	10	1050*	11	1966	25
									26
190	0.85	0.05	160	94	66	940	62	1967 Gas sold to Canadian Mon-	27
4	0.85	0.05	3	-	3	940	3	1967 tana Gas Company Limited	28
47	0.90	0.05	40	18	22	1000	22	1968	29
35	0.90	0.05	30	-	30	1000	30	1968	30
4	0.90	0.05	3	-	3	1000	3	1967	31
									32
14	0.90	0.05	12	-	12	1020	12	1958 Presently considered beyond economic reach	33
									34
11	0.85	0.05	8	-	8	980	8	1961 Presently considered	35
5	0.85	0.05	4	-	4	1050	4	1961 beyond economic reach	36
									37
1800	0.04	0.25	540	241	299	1020*	305	1961 Gas sold to Trans-Canada Pipe Lines Limited	38
									39
190	0.80	0.45	82	30	52	1050	55	1967 Gas used to maintain	40
30	0.85	0.45	14	-	14	1000	14	1965 pressure in Windfall field	41
770	0.04	0.35	200	147	53	1000	53	1966	42
									43
440	0.75	0.25	250	8	242	980	237	1967 Gas used to maintain pressure in Windfall field	44
									45
3	0.75	0.05	2	-	2	980	2	1961 Presently considered	46
14	0.80	0.05	11	-	11	1000	11	1960 beyond economic reach	47
14	0.80	0.05	10	-	10	1000	10	1961	48

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINC

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	PLOVER LAKE										
2	VIKING										
3	POUCE COUPE										
4	PEACE RIVER A	1922	2,300	0.572	620	94	25,700	25	0.18	0.30	0.93
5	PR (OTHER)										
6	CADOMIN										
7	POUCE COUPE SOUTH										
8	DOE CREEK										
9	PEACE RIVER A	1953	3,240	0.573	800	103	6,700	17	0.17	0.30	0.91
10	PEACE RIVER B	1953	3,240	0.573	800	103	8,500	23	0.17	0.30	0.91
11	PR (OTHER)										
12	CADOTTE										
13	GETHING										
14	CADOMIN										
15	TRIASSIC										
16	PREVO										
17	MANNVILLE										
18	PEKISKO A	1958	6,580	0.692	2330	162	2,490	25	0.10	0.20	0.83
19	PRINCESS										
20	2WS A	1940	2,190	0.575	820	74	33,310	5	0.22	0.40	0.90
21	2WS (OTHER)										
22	BOW ISLAND										
23	BASAL COLORADO										
24	BASAL MANNVILLE C	1940	3,230	0.642	1550	87	2,220	23	0.20	0.30	0.83
25	MANNVILLE (OTHER)										
26	BSL MANN A ASSOC	1940	3,170	0.604	1550	87	1,050	23	0.20	0.30	0.82
27	MANN ASSOC (OTHER)										
28	JEFFERSON	1940	3,190	0.820	1590	100	6,940	14	0.08	0.25	0.82
29	JEFFERSON ASSOC										
30	PROVOST										
31	VIKING A & B	1946	2,510	0.602	860	82	625,000	7	0.22	0.60	0.89
32	VIKING (OTHER)										
33	MANNVILLE										
34	RAINBOW										
35	SLAVE POINT										
36	SULPHUR POINT										
37	SULPHUR POINT ASSOC										
38	MUSKEG										
39	MUSKEG SOLN										
40	KEG RIVER 23-108-7	1967	6,050	0.697	2570	140	160	396	0.03	0.30	0.80
41	KEG RIVER (OTHER)										
42	KEG RIVER A ASSOC	1965	6,020	0.777	2570	195	340	159	0.09	0.10	0.82
43	KEG RIVER F ASSOC	1966	5,870	0.695	2480	180	2250	79	0.07	0.15	0.85
44	KEG RIVER Q ASSOC	1966	5,740	0.703	2420	175	160	248	0.07	0.10	0.85
45	KEG RIVER ASSOC (OTHER)										
46	KEG RIVER A SOLN	1965	6,380								
47	KEG RIVER B SOLN	1965	5,970								
48	KEG RIVER E SOLN	1966	5,930								
49	KEG RIVER F SOLN	1966	6,090								
50	KEG RIVER O SOLN	1966	6,050								
51	KEG RIVER SOLN (OTHER)										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)			
INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/68 BCF	REMAINING MARKETABLE GAS MAY 31/68 BCF	GROSS HEATING VALUE BTU CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
18	0.90	0.05	15	-	15	1000	15	1962	PRESENTLY CONSIDERED	2
									BEYOND ECONOMIC REACH	
										3
150	0.70	0.05	100	85	15	1000	15	1966	GAS SOLD TO WESTCOAST	4
2	0.80	0.05	2	-	2	1000	2	1961	TRANSMISSION COMPANY	5
4	0.85	0.05	3	-	3	1060	3	1965	LIMITED	6
										7
5	0.60	0.05	3	2	1	1000	1	1964	GAS SOLD TO WESTCOAST	8
32	0.75	0.05	23	18	5	1040	5	1965	TRANSMISSION COMPANY	9
55	0.75	0.05	39	31	8	1040	8	1965	LIMITED AND PEACE RIVER	10
5	0.70	0.05	3	-	3	1040	3	1965	TRANSMISSION COMPANY	11
9	0.70	0.05	6	-	6	1040	6	1964	LIMITED	12
16	0.80	0.05	12	11	1	1000	1	1965		13
4	0.85	0.05	3	2	1	1000	1	1963		14
18	0.80	0.05	14	-	14	1000	14	1965		15
										16
5	0.85	0.10	4	-	4	1020	4	1966		17
44	0.85	0.10	34	7	27	1110*	30	1966	GAS SOLD TO TRANS-	18
									CANADA PIPE LINES LIMITED	
										19
60	0.80	0.05	45	5	40	970	39	1967	GAS SOLD TO TRANS-	20
7	0.75	0.05	5	-	5	970*	5	1965	CANADA PIPE LINES LIMITED	21
2	0.75	0.05	1	-	1	1010	1	1965		22
9	0.75	0.05	6	2	4	1020*	4	1966		23
38	0.85	0.05	31	1	30	1020*	31	1965		24
22	0.85	0.05	18	7	11	1020*	11	1967		25
18	0.90	0.05	15	5	10	1020*	10	1966		26
14	0.90	0.05	12	9	3	1020*	3	1966		27
30	0.85	0.05	24	3	21	1030*	22	1965		28
1	0.85	0.05	1	-	1	1030*	1	1965		29
										30
960	0.85	0.02	800	245	555	1030	572	1967	GAS SOLD TO TRANS-CANADA	31
3	0.80	0.05	3	-	3	1030	3	1967	PIPE LINES LIMITED AND	32
20	0.85	0.05	16	-	16	1000	16	1961	SUPPLIES LOCAL UTILITY	33
										34
4	0.90	0.15	3	-	3	1050*	3	1968	PRESENTLY CONSIDERED	35
29	0.85	0.15	22	-	22	1050*	23	1968	BEYOND ECONOMIC REACH	36
1	0.80	0.15	1	-	1	1080*	1	1968		37
8	0.90	0.15	6	-	6	1080*	6	1968		38
5	0.65	0.30	2	-	2	1100*	2	1968		39
12	0.90	0.10	10	-	10	1100*	11	1968		40
13	0.85	0.10	10	-	10	1100*	11	1968		41
32	0.85	0.15	23	-2	25	1100*	28	1968		42
74	0.85	0.10	57	-	57	1100*	63	1967		43
18	0.85	0.10	14	-	14	1100*	15	1968		44
20	0.85	0.10	15	-	15	1100*	17	1968		45
110	0.75	0.20	68	1	67	1100*	74	1968		46
91	0.45	0.20	33	-	33	1100*	36	1967		47
19	0.65	0.15	11	-	11	1100*	12	1967		48
150	0.75	0.15	97	1	96	1100*	106	1967		49
34	0.50	0.25	13	-	13	1100*	14	1968		50
100	0.65	0.20	50	-	50	1100*	55	1968		51

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINC

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DISCOVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESSIBILITY FACTOR FRACTION
1	Rainbow South										
2	Sulphur Point										
3	Muskeg										
4	Keg River Assoc										
5	Keg River A Soln	1965	6,370								
6	Keg River B Soln	1966	6,460								
7	Keg River E Soln	1966	6,440								
8	Keg River Soln (Other)										
9	Redland										
10	Belly River										
11	Viking										
12	Mannville										
13	Redwater										
14	Viking										
15	Mannville										
16	D-1										
17	D-3 Soln	1948	3,210								
18	Red Willow										
19	Viking										
20	Mannville										
21	Retlaw										
22	Bow Island										
23	Basal Colorado										
24	Mannville B & D	1959	3,570	0.711	1720	95	3,990	7	0.22	0.30	0.79
25	Mannville J	1959	3,110	0.709	1700	94	1,250	23	0.21	0.40	0.81
26	Mannville (Other)										
27	Rundle										
28	Rundle Assoc										
29	Rich										
30	Lower Mannville A	1953	4,800	0.650	1270	137	3,810	13	0.12	0.30	0.87
31	Richdale										
32	Viking										
33	Mannville										
34	Rochester										
35	Viking										
36	Mannville										
37	Wabamun										
38	Rowley										
39	Belly River										
40	Viking										
41	Mannville										
42	Mannville Assoc										
43	Pekisko A Assoc	1960	4,410	0.707	1500	119	6,780	22	0.08	0.20	0.82
44	Pekisko Soln										
45	Rycroft										
46	Bluesky										
47	Gething										
48	Saddle Hills										
49	Cadotte D	1957	3,640	0.569	930	115	5,380	17	0.21	0.30	0.92
50	Peace River										
51	Gething										
52	Belloy A	1957	6,970	0.647	2600	155	1,050	35	0.10	0.25	0.82

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
22	0.85	0.15	16	-	16	1050*	17	1968	PRESENTLY CONSIDERED	2
7	0.90	0.20	5	-	5	1080*	5	1967	BEYOND ECONOMIC REACH	3
15	0.85	0.15	10	-	10	1100*	11	1967		4
34	0.75	0.25	19	-	19	1100*	21	1967		5
26	0.75	0.15	17	-	17	1100*	19	1967		6
57	0.75	0.25	32	-	32	1100*	35	1968		7
3	0.75	0.35	2	-	2	1100*	2	1967		8
										9
1	0.65	0.05	1	-	1	1000	1	1966		10
3	0.80	0.05	2	-	2	1000	2	1961		11
18	0.85	0.05	15	3	12	1070	13	1966	GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED	12
										13
26	0.75	0.05	19	1	18	1040	19	1965	SUPPLIES LOCAL UTILITY AND	14
1	0.80	0.05	1	1	< 1	1050	< 1	1960	GAS SOLD TO CANADIAN	15
4	0.85	0.05	3	2	1	1070	1	1967	INDUSTRIAL GAS & OIL LTD.	16
240	0.60	0.65	49	12	37	1220*	45	1965		17
										18
14	0.80	0.05	10	-	10	1020	10	1962	PRESENTLY CONSIDERED	19
12	0.80	0.05	9	-	9	1100	10	1962	BEYOND ECONOMIC REACH	20
										21
8	0.75	0.05	6	1	5	950	5	1968	GAS SOLD TO TRANS-CANADA	22
8	0.75	0.05	6	-	6	1020	6	1965	PIPE LINES LIMITED	23
27	0.90	0.10	22	5	17	1000	17	1968		24
21	0.90	0.05	18	-	18	1000	18	1967		25
47	0.85	0.10	35	-	35	1000	35	1968		26
2	0.85	0.10	1	-	1	1010	1	1966		27
2	0.90	0.10	2	-	2	1010	2	1966		28
										29
16	0.85	0.10	12	1	11	1100	12	1961	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED	30
										31
14	0.75	0.05	10	-	10	1010	10	1961	PRESENTLY CONSIDERED	32
11	0.75	0.05	8	-	8	1050	8	1961	BEYOND ECONOMIC REACH	33
										34
4	0.80	0.05	3	-	3	1000	3	1953	PRESENTLY CONSIDERED	35
25	0.75	0.05	18	-	18	1000	18	1953	BEYOND ECONOMIC REACH	36
6	0.90	0.05	5	-	5	1070	5	1953		37
										38
6	0.80	0.05	4	-	4	1000	4	1964	GAS SOLD TO TRANS-	39
10	0.85	0.05	8	-	8	1040	8	1966	CANADA PIPE LINES LIMITED	40
12	0.85	0.05	10	-	10	1070	11	1964		41
10	0.85	0.05	8	-	8	1070	9	1965		42
47	0.90	0.10	38	1	37	1080*	40	1963		43
8	0.65	0.25	4	-	4	1100*	4	1967		44
										45
7	0.80	0.05	5	3	2	1040	2	1961	SUPPLIES LOCAL UTILITY	46
13	0.90	0.05	11	1	10	1040	10	1961		47
										48
37	0.70	0.05	25	-	25	1020	26	1965		49
11	0.70	0.05	7	-	7	1020	7	1965		50
5	0.80	0.05	4	-	4	980	4	1965		51
22	0.80	0.15	15	-	15	1030	15	1965		52

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DIS-COVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESS-IBILITY FACTOR FRACTION
1	SAMSON										
2	BLAIRMORE ASSOC										
3	BLAIRMORE SOLN										
4	SARCEE										
	RUNDLE A	1954	9,750	0.719	3790	178	3,100	103	0.08	0.20	0.88
5	SARCEE WEST										
6	KOOTENAY 17-23-4	1957	11,030	0.673	3650	225	500	45	0.10	0.35	0.95
7	SAVANNA CREEK										
8	RUNDLE A	1954	8,350	0.657	2770	135	7,980	219	0.03	0.15	0.78
9	SEDALIA										
10	VIKING A	1954	2,660	0.600	930	87	53,270	9	0.17	0.40	0.89
11	VIKING (OTHER)										
12	MANNVILLE										
13	SEDGEWICK										
14	VIKING										
15	BASAL MANNVILLE A	1954	2,940	0.635	980	94	2,310	11	0.30	0.20	0.86
16	MANNVILLE (OTHER)										
17	SEIU LAKE										
18	VIKING										
19	MANNVILLE										
20	SEPTEMBER LAKE										
21	MANNVILLE										
22	MANNVILLE ASSOC										
23	WABAMUN										
24	SEXSMITH										
25	DUNVEGAN										
26	SIBBALD										
27	VIKING A	1950	2,530	0.579	1000	88	9,870	6	0.22	0.30	0.89
28	VIKING (OTHER)										
29	BASAL COLORADO										
30	BANFF										
31	SIMONETTE										
32	CADOTTE										
33	CADOMIN A	1960	8,110	0.661	2970	164	1,480	16	0.09	0.35	0.85
34	WABAMUN A	1959	11,240	0.813	4950	219	250	154	0.08	0.15	0.87
35	WABAMUN B	1960	11,120	0.813	4870	219	250	116	0.08	0.15	0.87
36	WABAMUN (OTHER										
37	D-3 SOLN	1958	11,580								
38	SMITH COULEE										
39	BOW ISLAND A	1947	2,050		GIP BASED ON MATERIAL BALANCE						
40	ST. ALBERT-BIG LAKE										
41	VIKING										
42	VIKING ASSOC										
43	OSTRACOD A	1952	3,710		GIP BASED ON MATERIAL BALANCE						
44	BASAL QUARTZ B	1952	3,800	0.667	1360	120	1,060	33	0.20	0.25	0.85
45	MANNVILLE (OTHER)										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
9	0.80	0.05	7	5**	3	1070*	3	1965 Gas sold to Northwestern	2
2	0.65	0.05	1					1965 Utilities, Limited	3
									4
210	0.85	0.15	150	40	110	1050*	116	1964 Gas sold to Canadian Western Natural Gas Company Limited	5
13	0.80	0.05	10	-	10	1020	10	1958	6
									7
340	0.85	0.30	200	28	172	1020	175	1966 Gas sold to Westcoast Transmission Company Limited	8
									9
140	0.80	0.05	100	6	94	1010*	95	1962 Gas sold to Trans-Canada	10
1	0.80	0.05	1	-	1	1010	1	1966 Pipe Lines Limited	11
1	0.75	0.05	1	-	1	1010	1	1962	12
									13
3	0.75	0.05	2	-	2	1000	2	1956	14
19	0.85	0.05	16	-	16	990	16	1968	15
10	0.85	0.05	8	-	8	990	8	1956	16
									17
8	0.80	0.05	6	-	6	1000	6	1966	18
27	0.80	0.05	21	-	21	1000	21	1963	19
									20
12	0.75	0.05	8	-	8	1030	8	1966 Presently considered	21
1	0.75	0.05	1	-	1	1030	1	1966 beyond economic reach	22
2	0.75	0.05	1	-	1	940	1	1966	23
									24
6	0.80	0.05	5	-	5	1000	5	1967 Supplies local Utility	25
									26
28	0.80	0.05	21	13	8	990	8	1966 Gas sold to Trans-Canada	27
7	0.80	0.05	6	-	6	990	6	1960 Pipe Lines Limited	28
13	0.80	0.05	10	-	10	990	10	1960	29
1	0.80	0.05	1	-	1	1050	1	1966	30
									31
9	0.90	0.05	7	-	7	1050	7	1957	32
12	0.85	0.05	10	-	10	1060	11	1966	33
34	0.85	0.35	19	-	19	1070	20	1966 Gas sold to Canadian	34
26	0.85	0.35	14	-	14	1070	15	1966 Utilities Limited	35
13	0.85	0.35	7	-	7	1070	7	1967	36
270	0.55	0.40	89	1	88	1020	90	1966	37
									38
32	0.85	0.05	26	21	5	930	5	1967 Gas sold to Canadian Montana Gas Company	39
									40
1	0.80	0.05	1	-	1	1070*	1	1965	41
2	0.80	0.05	2	-	2	1070*	2	1957	42
98	0.85	0.05	80	61	19	1070*	20	1962 Gas sold to Canadian	43
26	0.85	0.05	21	-	21	1070*	22	1964 Industrial Gas & Oil Ltd	44
10	0.85	0.05	8	-	8	1070*	9	1964	45

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	Standard										
2	Viking A	1956	4,180	0.634	1290	86	5,550	8	0.20	0.30	0.84
3	Steep Creek										
4	Gething										
5	Triassic										
6	Permo-Penn 26-66-7	1956	10,470	0.658	4350	240	1,100	35	0.06	0.30	0.91
7	Stettler										
8	Viking										
9	D-2 Soln										
10	D-3 Soln										
11	Stolberg										
12	Rundle A	1957	12,730	0.641	5100	200	1,480	122	0.05	0.20	0.99
13	St. Paul										
14	Mannville										
15	Strathmore										
16	Belly River										
17	Viking										
18	Rundle										
19	Strome										
20	Mannville										
21	Sturgeon Lake										
22	Gething										
23	Gilwood										
24	Sturgeon Lake South										
25	Gething 19-69-25	1954	5,200	0.611	1700	116	1,100	34	0.15	0.30	0.86
26	Gething (Other)										
27	Triassic Assoc										
28	Triassic Soln										
29	Permo-Penn										
30	D-1										
31	D-3 Assoc										
32	D-3 Soln	1953	8,850								
33	Sundre										
34	Mannville										
35	Mannville Assoc										
36	Rundle A Assoc	1955	9,050	0.647	3670	202	1,660	16	0.10	0.20	0.90
37	Rundle A Soln	1955	9,050								
38	RUND Soln (Other)										
39	Sunnynook										
40	Viking										
41	Mannville										
42	Swalwell										
43	Viking										
44	Pekisko A Assoc	1963	5,300	0.685	1790	144	4,000	32	0.08	0.25	0.83
45	Swan Hills										
46	Gething										
47	BH LK A & B Soln	1957	8,300								

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS
26	0.80	0.05	20	-	20	1000	20	1963
6	0.85	0.05	5	-	5	1020	5	1961 PRESENTLY CONSIDERED
9	0.85	0.10	7	-	7	1030	7	1961 BEYOND ECONOMIC REACH
17	0.90	0.20	12	-	12	1030	12	1961
3	0.80	0.05	2	-	2	1020	2	1963 GAS SOLD TO CANADIAN
21	0.30	0.90	1	-	1	1130	1	1966 WESTERN NATURAL GAS
14	0.55	0.95	1	-	1	1140	1	1966 COMPANY LIMITED
86	0.90	0.10	70	-	70	1040	73	1958
5	0.75	0.10	4	4	1	1000	1	1966 SUPPLIES LOCAL UTILITY
14	0.80	0.05	11	3	8	1000	8	1963 GAS SOLD TO CANADIAN
9	0.80	0.05	7	-	7	1000	7	1963 WESTERN NATURAL GAS
2	0.80	0.05	1	-	1	1000	1	1963 COMPANY LIMITED
2	0.90	0.05	1	-	1	1030	1	1966 SUPPLIES LOCAL UTILITY
13	0.85	0.05	10	-	10	1000	10	1967 PRESENTLY CONSIDERED
1	0.85	0.15	1	-	1	1000	1	1967 BEYOND ECONOMIC REACH
21	0.85	0.10	16	-	16	1000	16	1967
23	0.85	0.05	19	-	19	1000	19	1967
3	0.85	0.10	2	-	2	1180	2	1967
13	0.65	0.70	3	-	3	1180	4	1965
2	0.85	0.05	2	-	2	1030	2	1967
4	0.90	0.20	3	1	2	1070	2	1967 GAS SOLD TO CANADIAN
10	0.90	0.25	7	-	7	1080	8	1961 UTILITIES LIMITED
270	0.55	0.45	83	15	68	1080	73	1965
6	0.85	0.10	4	-	4	1020	4	1964
10	0.90	0.10	8	-	8	1020	8	1966
21	0.85	0.15	15	-	15	1060*	16	1964
59	0.45	0.35	17	-	17	1060*	18	1965
13	0.60	0.35	5	-	5	1060*	5	1965
1	0.75	0.05	1	-	1	1020	1	1966 GAS SOLD TO TRANS-CANADA
16	0.85	0.05	13	-	13	1020	13	1966 PIPE LINES LIMITED
4	0.80	0.05	3	-	3	1000	3	1966
43	0.85	0.05	35	-	35	1100	39	1966
2	0.90	0.05	1	-	1	1050	1	1962
1,090	0.45	0.35	320	18	302	1200*	362	1966 GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED

TABLE 1A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DISCOVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	Swan Hills South										
2	BH LK Soln	1959	7,450								
3	Sylvan Lake										
4	Viking										
5	Glauconitic A	1953	7,100	0.750	2420	155	6,290	31	0.13	0.30	0.79
6	Ostracod B	1963	7,790	0.730	2650	160	2,230	13	0.17	0.30	0.82
7	Lower Mannville A	1955	7,170	0.730	2470	160	2,830	18	0.13	0.30	0.82
8	Lower Mannville C	1953	7,130	0.724	2450	160	2,260	13	0.15	0.30	0.80
9	Lower Mannville D	1953	6,890	0.730	2410	155	2,620	16	0.13	0.30	0.81
10	Mannville (Other)										
11	Mannville Assoc										
12	Jurassic										
13	Jurassic A Assoc	1962	7,410	0.690	2500	160	3,010	21	0.12	0.30	0.83
14	JUR Assoc (Other)										
15	Jurassic Soln										
16	Elkton-Shunda A	1955	7,140	0.750	2470	160	3,380	17	0.08	0.25	0.79
17	Shunda B	1953	7,210	0.750	2500	160	1,790	23	0.10	0.25	0.79
18	Pekisko L	1963	6,920	0.738	2380	138	3,220	36	0.11	0.25	0.79
19	Rundle (Other)										
20	Rundle Assoc										
21	Rundle Soln										
22	D-3 A Assoc	1961	9,400	0.738	3490	210	1,800	41	0.06	0.20	0.87
23	D-3 Soln										
24	Taber South										
25	Bow Island A	1963	2,300	0.595	540	80	12,410	6	0.20	0.30	0.94
26	Bow Island (Other)										
27	Tangent										
28	Peace River										
29	Gething A	1951	2,450	0.556	1020	83	11,490	12	0.26	0.35	0.88
30	Gething (Other)										
31	Triassic A	1951	2,850	0.588	1190	93	12,590	4	0.18	0.30	0.86
32	Triassic B	1951	2,880	0.600	1200	94	12,980	3	0.22	0.30	0.86
33	Triassic (Other)										
34	Telfordville										
35	Mississippian										
36	Wabamun										
37	Thorhild										
38	Mannville A	1963	2,570	0.595	740	85	2,550	12	0.25	0.30	0.91
39	Mannville (Other)										
40	Three Hills Creek										
41	Belly River										
42	Viking										
43	Pekisko	1953	5,770	0.695	1720	152	43,770	27	0.05	0.35	0.85
44	Leduc										
45	Tur[illegible]										
46	Bow Island										
47	Mannville										
48	Mannville Assoc										
49	Turner Valley										
50	Rundle Assoc	1936	6,000								
51	Rundle Soln	1936	8,390								

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS	
									1
570	0.45	0.30	180	12	168	1120*	188	1966 Gas sold to Northwestern Utilities Limited	2
									3
4	0.85	0.05	3	-	3	1010*	3	1966	4
210	0.85	0.10	160	24	136	1100*	150	1964 Gas sold to Trans-Canada	5
27	0.85	0.10	21	1	20	1100*	22	1964 Pipe Lines Limited	6
34	0.85	0.10	26	5	21	1100*	23	1964	7
22	0.85	0.10	17	7	10	1100*	11	1964	8
28	0.85	0.10	21	3	18	1100*	20	1964	9
45	0.85	0.10	34	1	33	1100*	36	1964	10
2	0.80	0.10	2	-	2	1100*	2	1964	11
25	0.85	0.10	19	-	19	1020*	19	1965	12
40	0.80	0.10	29	-	29	1020*	30	1965	13
3	0.85	0.10	2	-	2	1020*	2	1966	14
23	0.60	0.45	8	-	8	1100*	9	1965	15
25	0.85	0.10	20	6	14	1100*	15	1965	16
24	0.85	0.10	18	-	18	1100*	20	1964	17
76	0.80	0.10	55	1	54	1100*	59	1966	18
39	0.85	0.10	29	-	29	1100*	32	1964	19
3	0.80	0.10	2	-	2	1100*	2	1964	20
38	0.60	0.35	15	-	15	1200*	18	1965	21
35	0.80	0.10	25	3**	27	1020*	28	1964	22
15	0.65	0.45	5						
									24
17	0.70	0.05	11	-	11	1000	11	1965 Presently considered	25
11	0.80	0.05	8	-	8	1000	8	1961 beyond economic reach	26
									27
10	0.90	0.05	9	-	9	1010	9	1967	28
76	0.70	0.05	50	-	50	1000	50	1967	29
3	0.70	0.05	2	-	2	1000	2	1967	30
22	0.90	0.05	19	-	19	1180	22	1967	31
22	0.90	0.05	18	-	18	1180	21	1967	32
5	0.90	0.05	4	-	4	1180	5	1967	33
									34
11	0.85	0.10	9	-	9	1110	10	1957	35
7	0.85	0.15	4	-	4	1090	4	1966	36
									37
12	0.85	0.05	10	-	10	1000	10	1966 Supplies Local Utility	38
1	0.85	0.05	1	-	1	1000	1	1964	39
									40
8	0.85	0.05	7	-	7	970	7	1963	41
8	0.80	0.05	6	-	6	1000	6	1963	42
190	0.85	0.05	150	20	130	1120*	146	1968 Gas sold to Trans-Canada	43
11	0.75	0.15	7	-	7	1100	8	1963 Pipe Lines Limited	44
									45
14	0.80	0.05	10	-	10	970	10	1968	46
15	0.85	0.05	11	-	11	1020	11	1968	47
10	0.85	0.15	7	-	7	1020	7	1968	48
									49
1570	0.90	0.70	410	293	117	1110*	130	1953 Gas sold to Canadian Western	50
1400	0.55	0.55	350	281	69	1110*	77	1953 Natural Gas Company Limited and Supplies Local Utility	51

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINC

	(1) POOL OR ZONE	(2) DIS-COVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESSIBILITY FACTOR FRACTION
1	TWEEDIE										
2	VIKING										
3	GRAND RAPIDS A		900	0.561	320	54	10,430	6	0.38	0.30	0.95
4	MANNVILLE (OTHER)										
5	TWINING NORTH										
6	MANNVILLE										
7	RUNDLE										
8	RUNDLE ASSOC	1961	5,370	0.679	1660	147	4,340	36	0.07	0.30	0.85
9	RUND ASSOC (OTHER)										
10	RUNDLE SOLN										
11	TWO CREEK										
12	TRIASSIC 11-63-16	1956	6,590	0.656	2200	170	1,100	12	0.20	0.30	0.88
13	USONA										
14	MANNVILLE 11-45-27	1954	5,110	0.706	1660	142	470	32	0.22	0.30	0.84
15	VERGER										
16	BOW ISLAND										
17	BASAL COLORADO										
18	MANNVILLE A	1954	3,410	0.600	1590	93	8,950	11	0.19	0.40	0.83
19	MANNVILLE (OTHER)										
20	RUNDLE										
21	VIKING-KINSELLA										
22	VIKING	1914	2,080	0.600	810	75	40,800	5	0.23	0.20	0.90
23	WAINWRIGHT	1951	2,330	0.590	740	83	6,750	13	0.26	0.25	0.91
24	MANNVILLE (OTHER)										
25	D-2										
26	D-3										
27	VIRGINIA HILLS										
28	MANNVILLE										
29	BELLOY A ASSOC	1961	6,150	0.690	1950	156	3,200	10	0.15	0.30	0.86
30	BH LK SOLN	1957	9,290								
31	SLAVE POINT										
32	VULCAN										
33	UPPER MANNVELLE										
34	BASAL MANNVILLE A		5,880	0.759	2320	125	2,390	9	0.15	0.35	0.85
35	TURNER VALLEY A	1960	5,940	0.760	2440	147	3,220	13	0.10	0.40	0.82
36	TV (OTHER)										
37	WAINWRIGHT										
38	VIKING										
39	MANNVILLE										
40	MANNVILLE ASSOC										
41	WASKAHIGAN										
42	CARDIUM										
43	DUNVEGAN A	1959	4,980	0.667	1490	145	15,890	10	0.16	0.45	0.85
44	DUNVEGAN (OTHER)										
45	CADOTTE										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
13	0.80	0.05	10	-	10	1000	10	1968	GAS SOLD TO GREAT CANADIAN	2
17	0.80	0.05	13	-	13	1040	14	1968	OIL SANDS LIMITED	3
24	0.80	0.05	18	-	18	1040	19	1968		4
										5
6	0.80	0.05	5	-	5	1100	6	1964		6
1	0.80	0.05	1	-	1	1110	1	1964		7
37	0.80	0.05	28	-	28	1110	31	1964		8
1	0.80	0.05	1	-	1	1110	1	1964		9
15	0.60	0.15	8	-	8	1110	9	1965		10
										11
12	0.90	0.05	10	-	10	1090	11	1956	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH	12
										13
12	0.90	0.05	10	-	10	1110	11	1955	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH	14
										15
3	0.75	0.05	2	-	2	1100	2	1964	GAS SOLD TO TRANS-	16
11	0.80	0.05	9	2	7	1010	7	1965	CANADA PIPE LINES LIMITED	17
60	0.85	0.05	49	2	47	1010	47	1965		18
14	0.85	0.05	11	-	11	1050	12	1964		19
2	0.85	0.10	2	-	2	1070	2	1964		20
										21
960	0.85	0.05	770	410	360	1000	360	1966	GAS SOLD TO NORTHWESTERN	22
41	0.80	0.05	31	3	28	1000	28	1966	UTILITIES LIMITED AND	23
40	0.80	0.05	30	14	16	1000	16	1966	SUPPLIES LOCAL UTILITY	24
18	0.80	0.05	14	5	9	990*	9	1966		25
1	0.85	0.05	1	-	1	990*	1	1961		26
										27
9	0.90	0.05	8	-	8	1040	8	1962	GAS SOLD TO NORTHWESTERN	28
20	0.85	0.10	15	-	15	1060	16	1962	UTILITIES LIMITED	29
220	0.40	0.40	54	5	49	1070*	52	1966		30
4	0.80	0.20	2	-	2	1070	2	1962		31
										32
5	0.85	0.15	4	-	4	1050	4	1968	GAS SOLD TO TRANS-	33
15	0.85	0.15	11	-	11	1050	12	1968	CANADA PIPE LINES LIMITED	34
19	0.80	0.20	13	-	13	1050	14	1966		35
4	0.80	0.20	2	-	2	1050	2	1966		36
										37
5	0.80	0.05	4	-	4	980	4	1959		38
15	0.85	0.05	12	-	12	940	11	1960		39
8	0.75	0.05	5	-	5	940	5	1968		40
										41
4	0.80	0.05	3	-	3	1060	3	1967		42
66	0.80	0.10	47	-	47	1110	52	1967		43
12	0.80	0.10	9	-	9	1110	10	1967		44
5	0.15	0.05	4	-	4	1070	4	1967		45

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	POOL OR ZONE	DIS- COVERY YEAR	AVERAGE WELL DEPTH FEET	RAW GAS SPECIFIC GRAVITY	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	AREA ACRES	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	COMPRESS- IBILITY FACTOR FRACTION
1	WATERTON										
2	RUNDLE C	1957	11,600	0.939	5770	185	15,700	53	0.05	0.20	0.90
3	RUNDLE D & E	1957	10,700	0.939	5040	195	7,450	102	0.05	0.20	0.83
4	RUNDLE (OTHER)										
5	RUNDLE-WABAMUN A	1959	10,350		GIP BASED ON MATERIAL BALANCE						
6	WABAMUN A	1958	13,000	0.779	5730	208	1,360	96	0.05	0.20	0.95
7	WABAMUN B	1958	13,400	0.648	5920	213	1,440	60	0.05	0.20	1.06
8	WABAMUN 31-6-3	1964	12,170	0.661	4020	205	2,000	58	0.05	0.20	0.91
9	WATTS										
10	VIKING										
11	MISSISSIPPIAN										
12	WAYNE-ROSEDALE										
13	BELLY RIVER										
14	VIKING A	1953	3,710	0.635	1170	108	49,870	6	0.20	0.30	0.87
15	VIKING B	1954	3,950	0.635	1170	108	9,940	9	0.16	0.30	0.87
16	VIKING (OTHER)										
17	GLAUCONITIC A	1953	4,400	0.663	1430	113	19,440	13	0.18	0.30	0.82
18	MANNVILLE (OTHER)										
19	MANNVILLE ASSOC										
20	WEST DRUMHELLER										
21	MANNVILLE										
22	RUNDLE										
23	D-2 ASSOC										
24	WESTEROSE										
25	VIKING										
26	MANNVILLE										
27	NISKU										
28	D-3 ASSOC	1952	6,900	0.710	2520	178	1,220	200	0.08	0.15	0.83
29	D-3 SOLN	1952	7,230								
30	WESTEROSE SOUTH										
31	WABAMUN										
32	D-3A	1953	7,640	0.814	2750	180	12,090	212	0.09	0.10	0.81
33	WESTLOCK										
34	VIKING	1949	2,600	0.582	840	95	75,270	13	0.19	0.35	0.90
35	VIKING (OTHER)										
36	MANNVILLE										
37	WEST PRAIRIE										
38	CADOTTE 18-72-17	1956	2,580	0.684	990	87	1,100	35	0.20	0.30	0.87
39	BLUESKY										
40	WHITECOURT										
41	BELLY RIVER										
42	VIKING										
43	MANNVILLE										
44	JURASSIC										
45	MISSISSIPPIAN										
46	WHITELAW										
47	BLUESKY										
48	BLSKY A-GETH A	1950	2,900	0.572	1110	76	2,600	14	0.21	0.45	0.87
49	GETHING B	1950	2,180	0.572	1150	76	3,720	6	0.20	0.25	0.86
50	TRIASSIC A	1950	3,240	0.580	1430	103	5,680	5	0.21	0.30	0.82
51	TRIASSIC (OTHER)										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
510	0.85	0.50	220	8	212	1040*	220	1964	GAS SOLD TO ALBERTA AND	2
450	0.85	0.50	190	38	152	1040*	158	1964	SOUTHERN GAS CO. LTD.	3
15	0.85	0.30	9	5	4	1040*	4	1964		4
1520	0.85	0.30	900	118	782	1040*	814	1964		5
67	0.80	0.40	33	-	33	1020	34	1964		6
47	0.80	0.20	31	11	20	1020	20	1964		7
40	0.85	0.15	29	-	29	1020	30	1966		8
										9
3	0.80	0.05	2	1	1	1030*	1	1960	SUPPLIES LOCAL UTILITY	10
1	0.80	0.05	1	-	1	1070	1	1955		11
										12
7	0.80	0.05	6	-	6	1000	6	1961		13
160	0.85	0.05	130	26	104	1090*	113	1965	GAS SOLD TO TRANS-CANADA	14
37	0.80	0.05	28	4	24	1090*	26	1963	PIPE LINES LIMITED.	15
29	0.85	0.05	23	1	22	1090*	24	1966	CANADIAN WESTERN NATURAL	16
150	0.85	0.05	120	25	95	1120	106	1966	GAS COMPANY LIMITED AND	17
67	0.85	0.05	55	8	47	1120	53	1961	SUPPLIES LOCAL UTILITY	18
3	0.85	0.05	2	2	< 1	1120	< 1	1962		19
										20
4	0.85	0.05	3	-	3	1100	3	1954		21
1	0.80	0.05	1	-	1	1040	1	1956		22
9	0.90	0.15	7	-	7	1090	8	1956		23
										24
3	0.80	0.05	2	-	2	1000	2	1961		25
7	0.80	0.05	5	-	5	1020	5	1953		26
2	0.90	0.05	1	-	1	1050	1	1959		27
130	0.90	0.20	90	-7	97	1050*	102	1959		28
150	0.70	0.20	83	8	75	1050*	79	1966	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED	29
										30
8	0.90	0.25	6	-	6	1090	7	1961		31
1620	0.90	0.15	1250	371	879	1060*	932	1966	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED	32
										33
320	0.80	0.05	250	53	197	1060	209	1964	GAS SOLD TO CANADIAN	34
8	0.80	0.05	6	-	6	1060	6	1964	INDUSTRIAL GAS & OIL LTD.	35
4	0.85	0.05	3	-	3	1100*	3	1962	AND SUPPLIES LOCAL UTILITY	36
										37
17	0.90	0.05	15	-	15	1040	16	1956	PRESENTLY CONSIDERED	38
6	0.90	0.05	5	-	5	990	5	1956	BEYOND ECONOMIC REACH	39
										40
2	0.85	0.05	1	-	1	1000	1	1963	INCLUDES AREAS FORMERLY	41
1	0.75	0.05	1	-	1	1050	1	1958	KNOWN AS CHRISTMAS CREEK	42
14	0.80	0.10	10	-	10	1050	11	1963	AND MCLEOD.	43
19	0.80	0.10	14	-	14	1070	15	1968		44
20	0.85	0.10	16	-	16	1060	17	1968		45
										46
2	0.80	0.05	1	-	1	1020	1	1961	SUPPLIES LOCAL UTILITY	47
14	0.85	0.05	12	5	7	1020	7	1966		48
13	0.85	0.05	11	1	10	1020	10	1966		49
21	0.85	0.05	16	-	16	1090	17	1966		50
10	0.90	0.05	9	-	9	1090	10	1957		51

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINC

	(1) POOL OR ZONE	(2) DIS-COVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESS-IBILITY FACTOR FRACTION
1	Wildcat Hills										
2	Rundle A	1958	9,880	0.699	3910	183	9,630	198	0.05	0.15	0.91
3	Wildhorse Creek										
4	Rundle A	1960	7,360	0.655	3200	137	1,490	153	0.08	0.20	0.87
5	Wildmere										
6	Mannville										
7	Wildunn Creek										
8	Viking A	1952	3,030	0.612	1110	90	8,810	4	0.25	0.40	0.86
9	Viking B	1953	3,090	0.589	1130	90	4,080	7	0.25	0.40	0.87
10	Willesden Green										
11	Belly River E	1967	5,050	0.703	1600	144	3,790	16	0.15	0.25	0.82
12	Belly River (Other)										
13	Cardium										
14	Cardium Soln	1954	6,190								
15	Mannville										
16	Mannville Assoc										
17	Mississippian										
18	Willingdon										
19	Viking										
20	Mannville										
21	D-3										
22	Wilson Creek										
23	Pekisko A	1960	7,040	0.683	2800	188	7,900	19	0.06	0.25	0.87
24	Banff A	1961	7,290	0.696	2800	194	1,100	37	0.06	0.25	0.87
25	Wimborne										
26	Viking										
27	Rundle										
28	D-2										
29	D-2 Assoc										
30	D-3 A Assoc	1954	7,480	0.781	3010	175	15,360	41	0.08	0.10	0.83
31	D-3 A Soln	1956	7,490								
32	Windfall										
33	Viking A	1955	5,140	0.630	1570	147	8,990	6	0.08	0.20	0.87
34	Rundle										
35	D-3										
36	D-3A Assoc	1955	9,050	0.812	3790	219	12,200	111	0.06	0.15	0.83
37	D-3A Soln	1957	9,100								
38	Winnifred										
39	BOW ISLAND A	1964	2,080	0.585	730	84	22,560	4	0.20	0.40	0.92
40	WINTERING HILLS										
41	BELLY RIVER										
42	VIKING D	1955	3,130	0.651	1280	89	1,100	19	0.20	0.30	0.86
43	VIKING (OTHER)										
44	VIKING ASSOC										
45	LOWER MANNVILLE C	1955	3,800	0.642	1570	98	2,160	8	0.20	0.30	0.81
46	MANNVILLE (OTHER)										
47	L MANN E ASSOC	1966	4,110	0.695	1410	103	2,810	11	0.17	0.35	0.80
48	MANN ASSOC (OTHER)										
49	RUNDLE										

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS		
										1
900	0.80	0.17	600	120	480	1050*	504	1967	GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD.	2
										3
140	0.85	0.20	96	-	96	1010	97	1964		4
										5
37	0.80	0.05	28	10	18	960*	17	1953	GAS SOLD TO NORTHWESTERN UTILITIES LIMITED	6
										7
19	0.60	0.05	11	-	11	1010	11	1967	GAS SOLD TO TRANS-	8
16	0.70	0.05	11	4	7	1010	7	1967	CANADA PIPE LINES LIMITED	9
										10
34	0.85	0.10	26	-	26	1000	26	1967		11
13	0.80	0.05	10	-	10	1000	10	1965		12
12	0.80	0.05	9	-	9	1040*	9	1961		13
440	0.40	0.55	83	5	78	1040*	81	1967	GAS SOLD TO ALBERTA AND	14
29	0.85	0.10	22	-	22	1100	24	1962	SOUTHERN GAS CO. LTD.	15
2	0.75	0.15	1	-	1	1100	1	1965		16
3	0.80	0.05	2	-	2	1100	2	1956		17
										18
3	0.25	0.05	2	-	2	980	2	1961	GAS SOLD TO WESTERN	19
16	0.25	0.05	12	3	9	990	9	1961	MINERALS LTD. AND	20
12	0.20	0.05	9	7	2	1000*	2	1965	SUPPLIES LOCAL UTILITY	21
										22
51	0.85	0.10	39	1	38	1120*	43	1966	GAS SOLD TO ALBERTA AND	23
15	0.85	0.15	11	-	11	1120*	12	1966	SOUTHERN GAS CO. LTD.	24
										25
2	0.75	0.05	1	-	1	1020	1	1956		26
2	0.90	0.10	1	-	1	1100	1	1961		27
1	0.85	0.15	1	-	1	1160	1	1959		28
2	0.80	0.15	2	-	2	1160	2	1959		29
370	0.80	0.25	220	36**	234	1000*	234	1968	GAS SOLD TO TRANS-	30
110	0.65	0.30	50					1966	CANADA PIPE LINES LIMITED	31
										32
17	0.75	0.05	12	-	12	1030	12	1963		33
5	0.85	0.05	4	2	2	1040	2	1961	GAS SOLD TO ALBERTA AND	34
3	0.90	0.35	2	-	2	1080*	2	1961	SOUTHERN GAS CO. LTD.	35
720	0.80	0.30	400	50**	460	1080*	497	1967	PRESSURE MAINTAINED BY	36
230	0.70	0.35	110					1966	PINE CREEK AND PINE NORTHWEST GAS	37
										38
19	0.85	0.05	16	-	16	1000	16	1966	SUPPLIES LOCAL UTILITY	39
										40
2	0.75	0.05	1	-	1	1000	1	1963		41
12	0.90	0.05	10	-	10	1010	10	1965		42
18	0.85	0.05	14	1	13	1010	13	1966	GAS SOLD TO TRANS-CANADA	43
9	0.75	0.05	7	-	7	1010	7	1965	PIPELINES LIMITED	44
13	0.80	0.05	10	-	10	1090	11	1965		45
15	0.85	0.10	11	-	11	1090	12	1966		46
16	0.75	0.10	11	-	11	1090	11	1966		47
5	0.80	0.05	4	-	4	1090	4	1966		48
2	0.80	0.05	1	-	1	1090	1	1963		49

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

	(1) POOL OR ZONE	(2) DIS-COVERY YEAR	(3) AVERAGE WELL DEPTH FEET	(4) RAW GAS SPECIFIC GRAVITY	(5) INITIAL PRESSURE PSIA	(6) RESERVOIR TEMPERATURE °F	(7) AREA ACRES	(8) AVERAGE PAY THICKNESS FEET	(9) POROSITY FRACTION	(10) LIQUID SATURATION FRACTION	(11) COMPRESS-IBILITY FACTOR FRACTION
1	WIZARD LAKE										
2	BELLY RIVER										
3	VIKING										
4	MANNVILLE										
5	MANNVILLE ASSOC										
6	D-3 A SOLN	1951	6,460								
7	WOKING										
8	PEACE RIVER										
9	SPIRIT RIVER										
10	BLUESKY										
11	PERMO-PENN										
12	KISKATINAW										
13	WOOD RIVER										
14	MANNVILLE										
15	WORSLEY										
16	D-3 A	1960	7,420	0.679	3310	184	3,380	28	0.06	0.20	0.90
17	D-3 B	1960	7,240	0.653	3240	180	3,720	50	0.07	0.20	0.90
18	D-3 D	1961	7,660	0.726	3090	181	1,000	60	0.10	0.20	0.89
19	D-3 E	1966	7,030	0.670	3060	169	500	42	0.11	0.20	0.91
20	D-3 G	1959	7,280	0.642	3300	180	3,700	42	0.06	0.20	0.91
21	D-3 (OTHER)										
22	D-3 ASSOC										
23	YEKAU LAKE										
24	VIKING										
25	ZAMA										
26	SLAVE POINT										
27	SULPHUR POINT										
28	SULPHUR PT ASSOC										
29	MUSKEG SOLN										
30	KEG RIVER SOLN										

SUB TOTAL

LESS THAN 10 BCF
CONFIDENTIAL

TOTAL RESERVES, MAY 31, 1968

TOTAL RESERVES WITHIN ECONOMIC REACH
TOTAL RESERVES BEYOND ECONOMIC REACH

OF ALBERTA, MAY 31, 1968 (14.65 PSIA AND 60°F)

(12) INITIAL GAS IN PLACE BCF	(13) POOL RECOVERY FRACTION	(14) SURFACE LOSS FRACTION	(15) INITIAL MARKETABLE GAS BCF	(16) MARKETABLE GAS PRODUCED MAY 31/68 BCF	(17) REMAINING MARKETABLE GAS MAY 31/68 BCF	(18) GROSS HEATING VALUE BTU CU FT	(19) REMAINING MARKETABLE GAS AT 1000 BTU BCF	DATE LAST REVIEWED AND REMARKS
2	0.75	0.05	1	-	1	1050	1	1966 Gas sold to North-
1	0.85	0.05	1	-	1	1070	1	1960 western Utilities, Limited
3	0.85	0.05	2	2	< 1	1120	< 1	1959
11	0.80	0.15	8	8	< 1	1120	< 1	1959
230	0.65	0.25	110	21	89	1250	111	1966
5	0.90	0.05	4	-	4	1040	4	1961 Supplies Local Utility
3	0.80	0.05	2	-	2	1040	2	1961
4	0.80	0.05	3	1	2	1040	2	1961
2	0.80	0.05	2	-	2	1060	2	1961
3	0.75	0.05	2	-	2	1070	2	1961
41	0.85	0.10	31	8	23	1100	25	1961 Gas sold to Trans-Canada Pipe Lines Limited
40	0.85	0.05	32	18	14	950*	13	1966 Gas sold to Westcoast
90	0.85	0.05	72	16	56	950*	53	1966 Transmission Company
39	0.85	0.10	30	14	16	950*	15	1966 Limited; Supplies Local
16	0.85	0.05	13	1	12	950*	11	1966 Utility
65	0.85	0.05	53	19	34	950*	32	1966
4	0.85	0.05	3	1	2	950*	2	1966
1	0.80	0.05	1	-	1	950*	1	1965
3	0.80	0.05	2	2	< 1	1070	< 1	1964 Injected into Leduc-Woodbend
45	0.85	0.10	34	-	34	1050*	36	1968 Presently considered
120	0.85	0.15	88	-	88	1050*	92	1968 beyond economic reach
8	0.85	0.15	6	-	6	1080*	6	1968
12	0.70	0.25	6	-	6	1100*	7	1968
84	0.70	0.25	43	-	43	1100*	47	1968
			46,803	7,776	39,027		40,911	
			809	-	809		849	
			1,680	-	1,680		1,825	
			49,292	7,776	41,516		43,585	
			46,555	7,776	38,779		40,702	
			2,737	-	2,737		2,883	

*MEASURED HIGHER HEATING VALUE

**INCLUDES SOLUTION GAS PRODUCTION

APPENDIX B

THE TRENDS IN EXPLORATION FOR AND THE GROWTH OF RESERVES OF GAS IN ALBERTA

The reserves considered in this section in determining the trends in the growth of reserves are the initial marketable reserves without adjustment for heating value.

Growth of Reserves

(1) Views of Trans-Canada

Trans-Canada did not present a detailed study of the trends in the growth of gas reserves in the Province. It estimated the initial marketable gas reserves in the Province, as of March 31, 1968, to be 48.9 trillion cubic feet. This estimate was made by adding the 1.9 trillion cubic feet increase which it estimated had occurred in the fields under contract to Trans-Canada and in certain other fields and areas, to the Board's estimate of the initial marketable reserves of the Province as of December 31, 1967.

Trans-Canada determined the average growth rate over the last two years by comparing its estimate of the initial marketable gas reserves at March 31, 1968, of 48.9 trillion cubic feet with the Board's estimate of initial marketable gas reserves as of December 31, 1965, of 43.0 trillion cubic feet. On this basis it concluded that the average two-year growth rate was 2.6 trillion cubic feet per year.

The applicant estimated the average long term growth rate from its estimate of the initial marketable gas reserves at March 31, 1968, and the Board's estimate of the initial marketable gas reserves as of June 30, 1955, of 15.3 trillion cubic feet (adjusted to 14.65 psia). It thus determined the long term growth rate to be 2.6 trillion cubic feet per year.

(2) Views of the Board

The Board, in OGCB Report 68-18(1) reviewed in detail the long term trend in the growth of initial marketable gas reserves in the Province to December 31, 1967, and concluded that the long term growth rate was 2.5 trillion cubic feet per year. The annual growth rate over the two-year period ending December 31, 1967, was 2.0 trillion cubic feet.

Although a further detailed study was not conducted the Board is satisfied that the changes which have occurred in the initial marketable reserves between December 31, 1967, and May 31, 1968, would not alter its interpretation of the long term growth rate. The Board, therefore, continues to interpret the long term growth rate as 2.5 trillion cubic feet per year.

The Board estimated the initial marketable gas reserves as of May 31, 1968, to be some 49.3 trillion cubic feet as shown in Appendix A. In OGCB Report 66-C(2) the Board estimated the initial marketable gas reserves of the Province as of February 28, 1966, to be 43.5 trillion cubic feet. The initial marketable reserves have thus increased by 5.8 trillion cubic feet over the last 27 months or at a rate of some 2.6 trillion cubic feet per year.

---

(1) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1967.

(2) Report on the Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. June 1966.

Ultimate Reserves

Neither Trans-Canada nor any of the interveners submitted new evidence respecting the ultimate reserves of the Province. However, CPA stated that "The Committee presently accepts the figure submitted by the Association at the hearing of the application by Alberta and Southern in July, 1964 of estimated potential recoverable raw gas reserves for Alberta of 150 Tcf, which is equivalent to 120 Tcf of marketable reserves".

The Board for the reasons presented in OGCB 68-18, and pending the results of a review currently being made, continues to believe that an ultimate gas reserve estimate for the Province of 100 trillion cubic feet is reasonable.

APPENDIX C

ALBERTA GAS REQUIREMENTS AND PERMIT COMMITMENTS

Trans-Canada did not present its own forecast of Alberta's 30-year requirements, but rather relied upon updating the Board forecast published in OGCB Report 67-C(1) so that it would relate to the period March 31, 1968 to March 31, 1998. The Utility Companies did not revise their previous forecast, reviewed and summarized in OGCB Report 66-C(2), other than to adjust the forecast to a level of 12.8 trillion cubic feet so that it would be applicable to the period 1968 to 1997. The Utility Companies' forecast excludes 'other' industrial consumption.

At the hearing the Board announced that the gas reserves of the Province would be assessed as at May 31, 1968. To conform with this date, the Board has decided to relate the requirements and permit commitments to the 30-year period June 1, 1968 to May 31, 1998.

In preparing its current assessment of Alberta gas requirements the Board conducted a review of its 1966 forecast in the light of actual gas consumption data received for 1966 and 1967. The results of this review are shown in the Table below.

---

(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. October, 1967.

(2) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. June, 1966.

	1966[**]			1967[**]		
	Board Forecast	Actual[*]	Error %	Board Forecast	Actual[*]	Error %
Domestic	50.0	49.9	0.2	52.0	51.8	0.4
Commercial	38.8	38.8	-	40.8	43.5	6.6
Industrial	120.6	118.1	2.1	121.6[Ŧ]	133.7	10.0

[*] Adjusted for degree days and 1000 Btu/cf

[**] Proportion of Forecast

[Ŧ] Includes adjustment to 'other' industrial forecast made in October 1967 (See OGCB 67-C)

The Board's conclusions in the light of these data for the various end-use categories are summarized below.

1. Domestic and Commercial Requirements

The close correspondence between actual and forecast domestic requirements indicated that at this time no change to the domestic forecast was appropriate. The Board believes that the error in the commercial forecast for 1967 in part reflects the recent significant expansion of office and apartment construction in Calgary and Edmonton. Although a deficiency has been experienced, the Board believes that its magnitude is not sufficient to justify changing the commercial forecast at the present time. Accordingly, the 1966 forecast of domestic and commercial gas consumption has been adjusted only to reflect the redefinition of the 30-year period.

2. Industrial Requirements

The industrial forecast embraces three categories: basic, special and 'other' industrial. The forecast was assessed for each category.

The basic industrial forecast has closely approximated actual experience over the last two years. As such, similarly to the domestic and commercial category, no adjustment other than for the 30-year period has been deemed suitable by the Board.

The special industrial loads, which constitute the bulk of the industrial category, comprise the principal industrial plants consuming gas in the Province. The forecast underestimated actual requirements by some 9 BCF in 1967. The Board decided that this deficiency was of sufficient magnitude to warrant it questioning those special industrial consumers exhibiting a significant discrepancy between forecast and actual requirements over the past two years. On the basis of information supplied by these industrial users and a reassessment of the 1966 forecast for other special loads, the Board has prepared a revised forecast of special industrial requirements. The changes in the projection are three in character: (a) the addition of new loads, which to some extent represents a transference from the previous contingency allowance, (b) a revision to special loads based upon information received from the company involved and (c) a transference of special industrial loads to contingency requirements.

Under Item (a), the new loads which now constitute firm requirements include a new fertilizer plant and the Great Canadian

Oil Sands plant at McMurray. Under item (b), revisions in particular concern fertilizer, chemical and power plants. Item (c) represents plant expansions which in 1966 were believed probable, but now appear less certain. In total, the net effect of the changes in special industrial requirements over the 30 years, 1968 to 1997, as compared to the 1966 forecast is close to one trillion cubic feet, comprising new special loads of 425 billion cubic feet, increases in existing loads of some 1,175 billion cubic feet and reductions of some 600 billion cubic feet.

The Board also reviewed its estimates of 'other' industrial requirements. These related to gas shrinkage and fuel requirements at the Empress and Edmonton Liquid Gas plants and requirements for Alberta Gas Trunk Line. The review indicated only minimal changes to the Board's previous forecast shown in OGCB Report 67-C for the requirements of Pacific Petroleums' Empress Plant, Edmonton Liquid Gas and Trunk Line. However, the Board believes an allowance for shrinkage and fuel requirements of the proposed Foothills Gas Plant of Alberta Natural Gas is appropriate. The Board's assessment of these requirements amounts to some 146 billion cubic feet over the 30-year period. Accordingly, the total of 'other' industrial requirements now includes an allowance of this magnitude relating to the Foothills plant.

3. Contingency Allowance

In ascertaining a suitable volume of gas for contingency requirements, the Board has made an estimate of the amount of gas which may be required if several of the existing industrial plants utilizing gas in the Province significantly expand their facilities in the future. Also, the Board has had regard for the likelihood of the location of new industrial plants in the Province, for instance further oil sands processing facilities. Furthermore, the Board has reviewed its allowance for the Peace River Mining project.

The Board received new evidence from Peace River Mining at the hearing which indicated a further deferral in the possible commencement of operations of the proposed iron ore plant. In 1966 the year of commencement was anticipated to be 1969. The corresponding inception time is now expected to be 1973. The construction of the plant is now dependent upon the successful operation of an intermediate sized plant in Ontario using scrap iron and upon possible further feasibility studies. Under these circumstances, the Board has decided that the previous allowance for the Peace River Mining project of some one trillion cubic feet should be reduced and that the requirements of the project would best be subsumed in the general contingency allowance rather than accorded separate treatment.

On the basis of this assessment, the Board has decided that a suitable total contingency allowance for the 30-year period would be some two trillion cubic feet. This level represents an increase of some 500 billion cubic feet over the 1966 total contingency allowance.

4. Summary

The Board's adjusted forecast and the Utility Companies' forecast are summarized in Table C-1 for the 30-year period January 1, 1968 to December 31, 1997.

The adjustment of the Board's forecast to the actual period of protection is shown in the following table:

	Bcf
Alberta Requirements January 1, 1968 to December 31, 1997 as per Table C-1	14,327
less Estimated Consumption January to May, 1968 inclusive	115
plus Forecast Consumption January to May, 1998 inclusive	300
Alberta Requirements June 1, 1968 to May 31, 1998	14,512

Therefore, the Board estimates Alberta requirements for the 30-year period June 1, 1968 to May 31, 1998 to total some 14,512 billion cubic feet.

Permit Commitments

The present permit commitments cover the volume of gas removed to May 31, 1968 and the maximum daily authorized withdrawal rates, under authority of each of the 28 permits issued as shown in Table C-2. At May 31, 1968 initial permit volumes totalled some 28.5 trillion cubic feet of gas. At this date approximately 4.8 trillion cubic feet or 17 per cent of initial permit volumes have been removed from the Province. The principal adjustments in permit commitments from the level shown in Table B-2 of OGCB Report 67-C relate to the volumes authorized for removal from the Province by Trans-Canada and Alberta and Southern. These adjustments are contained in Permit No. TC 67-7, issued on October 18, 1967 and the amendments to Permit No. AS 64-3 issued on October 18, 1967.

TABLE C-1

SUMMARY OF FORECASTS OF ALBERTA GAS REQUIREMENTS FOR PERIOD JANUARY 1, 1968 TO DECEMBER 31, 1997

(Billions of Cubic Feet of 1,000 Btu Gas)

	Utility Companies 1966*	Revised Board 1966
Domestic		
1968 Annual	54.2	53.9
1997 Annual	113.0	123.4
30-year Total	2,450.3	2,587.0
Commercial		
1968 Annual	43.1	42.0
1997 Annual	90.9	103.0
30-year Total	1,963.3	2,111.0
Industrial and Contingency		
1968 Annual	130.1	143.2
1997 Annual	423.5	474.7
30-year Total	9,198.9	9,628.9
Total		
1968 Annual	227.4	239.1
1997 Annual	627.4	701.1
30-year Total	13,612.7	14,326.9
Equivalent Average Annual Growth Rate to Achieve Terminal Year (%)	3.6	3.8
Equivalent Average Annual Growth Rate to Achieve 30-Year Total (%)	4.4	4.4

*Industrial and Total numbers adjusted to include Board's revised estimate of 'other' industrial consumption.

TABLE C-2

PERMIT COMMITMENTS

(All Volumes at 14.65 Psia and 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMcf	PERMITTED WITHDRAWALS MAXIMUM ANNUAL Bcf	TOTAL Bcf	WITHDRAWN TO MAY 31, 1968 Bcf	REMAINING AUTHORIZED WITHDRAWAL Bcf
AS 64-3	ALBERTA AND SOUTHERN GAS CO. LTD.					
	Bigstone, Brazeau River, Caroline, Carson Creek, Carson Creek North, Crossfield (Rundle Pool), Ferrier (Viking A and Cardium B Pools), Harmattan-Elkton (D-3 A Pool), Homeglen-Rimbey, Judy Creek, Kaybob, Marlboro, Minnehik-Buck Lake, Pembina (Lobstick Glauconitic and Lobstick Ostracod Pools), Pine Creek, Pine North-west, Sundre, Swan Hills, Swan Hills South, Sylvan Lake, Virginia Hills, Waterton, Westerose South, Westward Ho, Wildcat Hills, Willesden Green, Wilson Creek, Windfall.	900.0	294.0	7,090.0	1,113.3	5,976.7
AS 67-4	ALBERTA AND SOUTHERN GAS CO. LTD.					
	Belloy, Berland River, Eaglesham, Fox Creek, Gold Creek, Hunter Valley, Kaybob South, Pembina (Pekisko B Pool), Tangent, Waskahigan, Wildhorse Creek.	150.0	49.0	1,200.0	-	1,200.0
CD 63-1	CANADIAN DELHI OIL LTD. - Medicine Hat	4.3	1.57	32.3	3.4	28.9
CM 54-1 and CM 61-2	CANADIAN-MONTANA PIPELINE COMPANY					
	Aden, Black Butte, Comrey, Knappen, Manyberries, Pakowki Lake, Pendent d'Oreille, Smith Coulee.	100.0	40.0	469.0 (1)	231.3	237.7

(1) Total initial marketable gas in the fields shown.

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14-65 PSIA AND 60^{0}F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT		PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWAN TO MAY 31, 1968 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
CP 63-1	CANADIAN PACIFIC OIL AND GAS LIMITED	- MEDICINE HAT	0.1	0.0365	0.750	0.105	0.645
BH 61-1	DELTA GAS & TRANSMISSION LTD.						
BS 61-1	BAILEY SELBURN OIL AND GAS LTD.						
CS 61-1	THE CALIFORNIA STANDARD COMPANY						
COG 61-1	CHARTER OIL AND GAS LTD.	MEDICINE HAT	9.5	3.5	71.0	-	71.0
SEL 61-1	SELBAY EXPLORATION LTD.						
JMW 61-1	J. MERRIL WRIGHT, JR.						
CEL 61-1	CROWFOOT EXPLORATION LTD.						
CMM 61-1	J. RAY MCDERMOTT & CO. LTD.						
MOG 61-1	MAYFAIR OIL AND GAS (1961) LTD.	MEDICINE HAT	8.3	3.0	62.0	8.2	53.8
ROC 61-1	RICHFIELD OIL CORPORATION						
ROC 65-2	RICHFIELD OIL CORPORATION	- MEDICINE HAT	0.26	0.088	2.0	0.1	1.9
HB 63-1	HUDSON'S BAY OIL AND GAS COMPANY LIMITED	- MEDICINE HAT	1.02	0.372	7.65	0.46	7.19
SPC 57-1	MANY ISLANDS PIPE LINES LTD.	- MEDICINE HAT	135.5	44.5	609.4	172.4	437.0
MO 66-1	MURPHY OIL COMPANY LTD.	- RED COULEE	0.6	-	0.5	-	0.5
NSU 64-1	THE BRITISH AMERICAN OIL COMPANY LIMITED						
	ROYALITE OIL COMPANY LIMITED	- ANTELOPE AND ESTHER	11.4	4.2	40.0	8.5	31.5
	SUN OIL COMPANY						
	UNITED CANSO OIL & GAS LTD.						

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60 °F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT		PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO MAY 31, 1968 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
	PEACE RIVER TRANSMISSION COMPANY LIMITED	- Pouce Coupe	6.0	0.6	13.0		
						12.5	20.2
	PEACE RIVER TRANSMISSION COMPANY LIMITED	- Pouce Coupe South	6.9	0.98	19.7		
B 64-1	PATRICK T. BUCKLEY	- Vanalta No. 4 Well	1.3 MMcf PER MONTH	0.01	-	0.06	-
PG 64-1	PROVO GAS PRODUCERS LIMITED	- Halliday, Richdale and Wildunn Creek	10.0	3.6	45.0	4.6	40.4
TC 67-7	TRANS-CANADA PIPE LINES LIMITED						
	Abee, Alderson, (2WS A and Bow Island A Pools), Atlee-Buffalo, Baptiste, Bashaw, Bellis, Berry, Bindloss Boyle, Brazeau River, Bruce, Calling Lake, Caroline (Viking A, Viking E and Basal Mannville A Pools), Carstairs, Cessford, Chigwell, Connorsville, Countess Craigend, Crossfield, Crossfield East, Drumheller, Edson, Enchant, Equity, Erskine, Fenn-Big Valley, Fenn-West, Figure Lake, Flat, Francis, Garrington (Mannville A and Leduc A Pools), Ghost Pine, Gilby, Hackett, Hamilton Lake, Harmattan East, Harmattan-Elkton (Rundle A Pool), Homeglen-Rimbey, Hussar, Innisfail, Killam, Little Bow, Lone Pine Creek, Long Coulee, Lookout Butte, Malmo, Marten Hills, Medicine River, Minnehik-Buck Lake, Nevis, New Norway, Olds, Oyen, Pincher Creek, Prevo, Princess, Provost, Retlaw, Rich, Rowley, Sedalia, Seiu Lake, Sibbald, Standard, Stettler, Sundre(Basal Mannville A and Basal Mannville B Pools), Sunnynook, Swalwell, Sylvan Lake,		2,170.0	720.0	17,100.0	2,696.0	14,404.0

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60° F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS			WITHDRAWN TO MAY 31, 1968 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
		MAXIMUM DAY MMCF	MAXIMUM ANNUAL BCF	TOTAL BCF		
	THORHILD, THREE HILLS CREEK, TROCHU, TWINING NORTH,					
	VERGER, VULCAN, WAYNE-ROSEDALE, WESTEROSE, WESTEROSE					
	SOUTH, WIMBORNE, WINTERING HILLS AND WOOD RIVER.					
WC 52-1	WESTCOAST TRANSMISSION COMPANY LIMITED AND					
	WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.					
	BRAEBURN, GORDONDALE, POUCE COUPE, POUCE COUPE SOUTH	125.0	35.0	388.0	228.9	159.1
WC 59-3	WESTCOAST TRANSMISSION COMPANY LTD.					
	SAVANNA CREEK, CROSSFIELD (CALGARY BASAL QUARTZ,					
	CALGARY RUNDLE, AND CALGARY WABAMUN POOLS)	162.2	53.1	1,081.2	283.1	798.1
WC 61-4	WESTCOAST TRANSMISSION COMPANY LIMITED AND					
	WESTCOAST TRANSMISSION COMPANY (ALBERTA) LIMITED					
	BOUNDARY LAKE SOUTH	VOLUMES NOT TO EXCEED THOSE AUTHORIZED IN PERMIT NO. WC 52-1				
WC 62-5	WESTCOAST TRANSMISSION COMPANY LIMITED AND					
	WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.					
	WORSLEY	53.3	16.0	220.0	67.9	152.1
		3,854.42	1,269.5565	28,451.50	4,830.825	23,620.735

APPENDIX D

THE MEETING OF ALBERTA'S REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

(1) Views of Trans-Canada

Trans-Canada did not present detailed evidence to show how Alberta's 30-year requirements for gas might be met but did estimate the surplus of gas in the Province employing the method currently used by the Board. The estimates of reserves and requirements were made by updating the Board's estimates. Since Trans-Canada did not have access to information on new discoveries the reserves of these discoveries were excluded from its estimates. It submitted that the long term trend in the growth of reserves was 2.6 trillion cubic feet per year.

Trans-Canada submitted a detailed table, included here as Table D-5, whereby it showed that the contractable gas reserves at March 31, 1968, exceeded the contractable requirements by 3.4 trillion cubic feet. It calculated that the future surplus at March 31, 1968 was 1.0 trillion cubic feet and that an overall surplus of 4.4 trillion cubic feet resulted after taking account of the contractable surplus of 3.4 trillion cubic feet. It determined the quantities included in the table in a manner similar to that followed by the Board, and any differences in interpretation are principally the result of differences in estimation or categorization of reserves and in the date of analysis. It submitted that the additional 2.1 trillion cubic feet of gas it is seeking authorization to remove from the Province is therefore surplus to the needs of Alberta.

(2) Views of Interveners

Alberta Division of the Canadian Petroleum Association. CPA did not present detailed evidence to show what Alberta's 30-year requirements would be or how the requirements would be met. However, it did estimate the gas surplus to Alberta's requirements using its estimate of the probable reserves of the Province as of December 31, 1967, and its estimate of provincial requirements.

It submitted that the average discovery rate for the years 1953 to 1964, inclusive, was 2.5 trillion cubic feet per year on a 1,000 Btu per cubic foot basis using its estimates of probable reserves.

CPA submitted that, using its estimates of probable reserves and the procedure for determining the surplus adopted by the Board, the contractable surplus at December 31, 1967, was 2.8 trillion cubic feet, the future deficiency before the release of reserves required to protect peak day in permits was 0.3 trillion cubic feet and the overall surplus after the release at the termination of the permits, of 0.8 trillion cubic feet of reserves required to protect the peak day in permits, was 3.3 trillion cubic feet. It added that its estimates excluded significant gas discoveries and developments in several areas of the Province including Quirk Creek, Whitecourt, Flat and Clarke Lake - Fox Creek. The details of its surplus calculations are included here as Table D-6.

While CPA, except for its use of probable reserves, used the procedure for calculating surplus employed by the Board, it disagreed with the procedure. Details of CPA's recommendations in this regard are discussed in Sections III and IV.

Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited. The Utility Companies submitted that they have no objection to granting the application if the Board finds, using its method of surplus assessment set out in OGCB Report 67-C(1), that there are sufficient volumes of established reserves surplus to the needs of the Province. Additional discussion of the Utility Companies' views in this regard is included in Sections III and IV.

Independent Petroleum Association of Canada. IPAC also made recommendations respecting suitable procedures to follow in assessing the surplus gas available in the Province. Its views are also discussed in more detail in Sections III and IV.

(3) Views of the Board

The Meeting of Alberta's Long Term Requirements (June 1, 1968 to May 31, 1998). The 30-year gas requirements for delivery to the markets within the Province (Alberta requirements) discussed in Appendix C have been estimated at some 14.5 trillion cubic feet. The peak day requirement in the thirtieth year is estimated to be some 3.4 billion cubic feet. The fields now connected to and supplying Alberta's requirements, together with their remaining reserves as of May 31, 1968, which total 6.5 trillion cubic feet, are shown in Table D-1. Thirty times the requirements of the first year of the period (taken as the 12 months starting June 1) is 7.4 trillion cubic feet. The contractable requirements, defined under the Board's policy set forth in OGCB Report 66-C(2) as the greater of 30 times the requirements of the first year of the period under consideration or the remaining reserves in those fields connected to and supplying Alberta requirements, are therefore 7.4 trillion cubic feet.

---

(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. October 1967.

The contractable requirements of the 30-year period have increased by 0.9 trillion cubic feet over the contractable requirements of the 30-year period considered in OGCB Report 67-C. This increase is higher than in the past, for two reasons. The requirements estimated for the first year of the period considered in OGCB Report 67-C were underestimated principally in the industrial category as described in Appendix C. Secondly, in view of the significance of the first year's requirements in the calculation of the contractable requirements, the Board, commencing with this report, has taken the requirements of the first year of the period as being the requirements of the first twelve months of the period, rather than the requirements of the initial calendar year. In prior reports, other than the immediately preceding report, the reserves connected to and supplying Alberta requirements have exceeded 30 times the requirements of the first year of the period and this calculation has not been as significant as it now is and may be in the future.

Table D-1 shows also the Board's interpretation of the reserve-delivery ratio of each of the fields and the average reserve-delivery ratio of the group of fields supplying Alberta requirements. The reserves are classified in the table between major reserves, oil field gas and small reserves plus reserves supplying small utilities. The reserve-delivery ratio is the initial gas in place adjusted for surface losses divided by the initial fully developed marketable gas deliverability. The ratios have been updated to take account of changes in reserves of pools, additional deliverability data and new discoveries.

---

(2) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. June, 1966.

It is reasonable to assume that the deliverability characteristics of the 0.9 billion cubic feet (7.4 - 6.5 = 0.9) of additional reserves needed to supply the contractable requirements will be similar to those of the contractable reserves of 6.5 billion cubic feet now connected to and supplying the Alberta requirements. On this basis, the Board estimates that of the total of some 7.4 billion cubic feet needed to supply the contractable Alberta requirements, some 5,600 billion cubic feet will be produced during the 30-year period and the remaining unproduced portion will be capable of sustaining a peak day delivery of some 560 million cubic feet in the thirtieth year. Therefore, total deliveries of about 8,900 billion cubic feet (14,500 - 5,600 = 8,900) and a thirtieth year peak day delivery of about 2840 million cubic feet (3,400 - 560 = 2,840) will be required from other sources.

The actual quantities of gas necessary to provide these deliveries may be calculated using the formula method presented in Appendix E of OGCB Report 64-11(3). With respect to the factors to be used in the formula, the Board believes that, since this gas must come in part from established gas reserves not now connected to local utilities nor authorized for removal from the Province and in part from gas reserves not yet developed, the factors should reflect the delivery characteristics of both of these sources of gas.

---

(3) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November 1964.

The Board has again reviewed the average reserve-delivery ratio to take account of changes which have occurred since the issuance of OGCB Report 67-C. It finds that the average reserve-delivery ratio of 2.0 previously used, remains applicable.

The Board has redetermined the average reservoir recovery factor of the gas in place adjusted for surface losses from a detailed review of these reserves. This particular recovery factor represents the fraction of the remaining marketable gas in place in the Province which will be recovered and is a fraction which declines as additional gas is produced. The change from the 0.84 previously used to 0.74 is principally the result of production since the last detailed review performed in 1964 but is also affected by the addition of large amounts of solution gas and adjustments to pool recovery factors not fully accounted for in year to year reviews.

From now connected sources and additional sources needed to supply the contractable requirements, for delivery during the period	5,600	
From additional sources for delivery during the period	8,900	
Total Alberta Requirements for delivery		14,500

From now connected sources and additional sources needed to supply the contractable requirements, to protect the thirtieth year peak(1)	1,800	
From additional sources to protect the thirtieth year peak(2)	3,200	
Total Alberta requirements for peak day protection		5,000
Total Alberta Requirements		19,500

(1) i.e. 7,400 - 5,600 = 1,800

(2) Determined as $R_p = 1.3\ FP_n - (1 - K)\ (1.3\ FP_n + A_1 S)$

$$= 1.3\ (2.0)\ (2840) - (1 - 0.74)\ \left[1.3\ (2.0)\ (2840) + 8{,}900\right]$$

$= 7{,}384 - 4{,}234 = 3{,}150$; say 3,200 billion cubic feet

It may be noted that the gas required from additional sources to protect the thirtieth year peak is reduced from 3600 billion cubic feet shown in the previous report to 3200 billion cubic feet. The reduction is the result of the reduction in the value of the average marketable gas recovery factor more than offsetting, in the formula, the effect of the increase in the peak day rate to be protected from additional sources.

The Remaining Permit Commitments

The permit commitments remaining at May 31, 1968, are shown in Appendix C to be some 23.6 trillion cubic feet before adjustments for heating value and deficiencies in reserves in certain permits.

The fields included in each of the permits are shown in Table D-3. The table also shows the Board's current estimate of the remaining reserves of marketable gas and the ratio of initial marketable gas in place to delivery capacity for each field. The table reflects changes in the remaining marketable reserves which have occurred since the preparation of OGCB Report 67-C. It also incorporates revisions to reserve-delivery ratios resulting from additional data respecting pool deliverability in relation to the reserves.

Changes have occurred principally as a result of the coalescence of pools and fields and improved conservation of solution gas such as occurred in the Beaverhill Lake pools in the Virginia Hills, Swan Hills, Swan Hills South and Judy Creek Fields.

Alberta and Southern, by Permit No. AS 64-3, is permitted to remove 170 billion cubic feet of gas from the Judy Creek, Swan Hills, Swan Hills South and Virginia Hills Fields as discussed in OGCB Report 67-C. The volume in the permit fields shown in Table D-4 includes the 170 billion cubic feet, since it appears that Imperial Oil Limited will be able to meet the requirements of Northwestern Utilities, Limited from the area and still have sufficient deliverability to provide the amount of gas in the fields under contract to Alberta and Southern during the term of Permit No. AS 64-3.

In Table D-3, the remaining reserves of the Crossfield Field, for which the three major permit holders, Alberta and Southern, Trans-Canada and Westcoast, have permits, have been apportioned among them as described in OGCB Report 67-C, on the basis of the Board's knowledge of their contracts.

Division of reserves between permittees or between permittees and provincial requirements have also been made for the Brazeau

River, Homeglen-Rimbey, Hunter Valley, Pembina, Sylvan Lake, Westerose South, Wayne-Rosedale and Medicine Hat fields as well as a number of other smaller fields.

The results of the Board analysis with respect to the meeting of the remaining permit commitments are shown in Table D-4. Columns 1 and 2 show respectively the remaining permit commitment and the maximum daily withdrawal authorized in each of the permits. These figures which were obtained from Appendix C, have been adjusted where necessary for any deficiencies in reserves in fields, pools and areas included in the permit, and have been converted to the basis of 1,000 Btu per cubic foot. The expiry date of each of the permits is shown in Column 3. Columns 4 and 5 present, where applicable, the Board's current estimate of the total remaining marketable reserves and the reserve-delivery ratio (both from Table D-3) of the fields included in each permit. Column 6 shows the composite correction factor for each of the permittees' systems for which peak load protection is provided, as determined from the illustrative deliverability schedules prepared for this report. The estimated quantity of marketable gas in place required to meet the peak day commitment in the terminal year of each permit is shown where applicable in Column 7. Column 8 shows the marketable gas equivalent of Column 7. These values were obtained by deducting from Column 7, the marketable gas equivalent of the gas that will remain in the reservoirs at abandonment. The total marketable gas required to meet the permit requirements, both deliveries and peak day, is shown in Column 9. Columns 10 and 11 present the Board's estimate of the marketable gas in the fields in the permits excess of the permit commitments before and after the expiry date of each permit.

In the case of permits where the removal of all the reserves in the permit fields has been authorized or where no allowance for maximum day protection has been made by the Board, entries in Columns 5 through 8, which support the calculation of marketable reserves required to meet the terminal year peak day, have been omitted.

The remaining commitment of the Westcoast Peace River permits provides for an adjustment, described more fully in OGCB Report 66-C and in Permit No. WC 62-5, related to the delivery of gas from the Worsley Field and the meeting of future requirements of an iron ore processing industry in the Peace River area. The reserves credited to these permits have been adjusted having regard for these provisions, field deliverability and the withdrawals taken from the area to December 31, 1965. The provision for this market in the estimated Alberta requirements is discussed in Appendix C.

Table D-4 shows that a total marketable gas reserve of 25.0 trillion cubic feet is required to meet the commitment of all subsisting permits of 24.5 trillion cubic feet. Since reserves of 27.1 trillion cubic feet are available, a surplus of 2.1 trillion cubic feet of gas exists in the fields named in the permits. After the expiry dates of the permits, several years before the end of the 30-year period, an additional 500 billion cubic feet, the amount allowed to meet the terminal year peak day deliveries for certain of the permits, will become excess to the existing permit commitments.

The Gas Surplus to Alberta's Requirements and the Permit Commitments

The surplus calculation, using the method adopted by the Board which has been discussed in detail in OGCB Report 66-C under the title of the Board Modified Method, is illustrated in Table D-7.

Table D-7 shows that the Board's estimate of contractable reserves, the reserves within economic reach (40.7 trillion cubic feet) less the deferred reserves (6.0 trillion cubic feet), totals some 34.7 trillion cubic feet. The deferred reserves are interpreted in Table D-8 as consisting of some 5.3 trillion cubic feet expected to be marketable within 30 years and 0.7 trillion cubic feet which the Board estimates will be deferred beyond the 30-year period. The contractable requirements include 7.4 trillion cubic feet needed to supply the Alberta contractable requirements (6.5 trillion cubic feet of which are now connected to supply Alberta's requirements) and 24.5 trillion cubic feet to meet the permit commitments. A comparison of the contractable reserves and contractable requirements results in a contractable surplus of 2.3 trillion cubic feet.

The table also shows that the remaining Alberta requirements total some 12.1 trillion cubic feet. These are made up of some 8.9 trillion cubic feet which the Board believes will have to be delivered during the 30-year period and some 3.2 trillion cubic feet which the Board estimates will be necessary to provide for the thirtieth year peak day.

The remaining and future reserves available to meet these Alberta requirements are shown to total some 12.5 trillion cubic feet. These are made up of 5.3 trillion cubic feet of deferred gas which the Board believes will be available within the 30-year period, some 2.2 trillion cubic feet of reserves now beyond economic reach but which the Board believes will be within economic reach within 30 years, and 5.0 trillion cubic feet of future reserves reflecting two years growth at the average long term growth rate. (In this instance the growth rate over the last two years is higher than the long term growth rate.) The 2.2 trillion cubic feet of reserves now beyond economic reach but expected to be available within 30 years was obtained taking 75 per cent of the reserves now considered beyond economic reach. No adjustment to this percentage was made for the Rainbow-Zama area in this report. A portion of the solution and non-associated gas reserves in the Rainbow-Zama area is expected to be available since only a portion of the oil reserves are expected to be subject to enhanced recovery schemes utilizing marketable gas and since Trunk Line is likely to extend a line to the Rainbow-Zama area in the early 1970's. This analysis results in the total remaining reserves exceeding the total remaining requirements by 0.4 trillion cubic feet. The procedure followed in these calculations is discussed more fully in OGCB Report 66-C.

The overall surplus from addition of the contractable surplus of 2.3 trillion cubic feet and the future surplus of 0.4 trillion cubic feet is 2.7 trillion cubic feet. This overall surplus will increase to 3.2 trillion cubic feet after release, at the end of the term of the permits, of the 0.5 trillion cubic feet allocated to protect peak day requirements in certain permits.

TABLE D-1

RESERVES AND RESERVE-DELIVERY RATIOS OF FIELDS SUPPLYING ALBERTA'S REQUIREMENTS FOR GAS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD		MARKETABLE GAS AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO[1] BCF/MMCFD
MAJOR RESERVES			
BEAVERHILL LAKE-FORT SASKATCHEWAN		400	0.8
BOW ISLAND		19	0.9
CARBON		135	0.9
FAIRYDELL-BON ACCORD		71	0.7
FOREMOST		19	0.8
JUDY CREEK		39	1.0
JUMPING POUND		314	3.7
JUMPING POUND WEST		661	7.7
MEDICINE HAT		355	3.6
MORINVILLE		63	1.6
OKOTOKS		124	4.0
PADDLE RIVER		162	1.2
SARCEE		116	1.5
ST. ALBERT-BIG LAKE		54	1.7
TURNER VALLEY		207	4.6
VIKING-KINSELLA		414	1.8
WAYNE-ROSEDALE		139	1.0
WESTLOCK		218	1.2
WORSLEY		112	0.4
	TOTAL	3,622	
	WEIGHTED AVERAGE		1.7
OIL FIELD GAS			
ACHESON		18	10.3
BONNIE GLEN		281	27.4
FENN-BIG VALLEY		10	20.8
GLEN PARK		10	28.0

---

[1] THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-1 (CONTINUED)

FIELD		MARKETABLE GAS AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
JUDY CREEK		220	35.2
LEDUC-WOODBEND		21	5.0
PEMBINA		805	36.0
REDWATER		45	26.8
SAMSON		3	3.8
SIMONETTE		90	27.5
STETTLER		2	6.0
STURGEON LAKE SOUTH		73	24.8
SWAN HILLS		292	40.5
SWAN HILLS SOUTH		151	40.5
VIRGINIA HILLS		42	38.0
WIZARD LAKE		111	30.9
	TOTAL	2,174	
	WEIGHTED AVERAGE		26.9
SMALL RESERVES PLUS RESERVES SUPPLYING SMALL UTILITIES			
ACHESON		24	1.2
ALDERSON		17	9.1
ALEXANDER		3	0.5
ATHABASCA		6	1.5
ATHABASCA EAST		2	0.6
ATIM		2	0.3
BANTRY		113	8.5
BEAVER CROSSING		1	0.3
BONNIE GLEN		7	3.5
BONNYVILLE		1	0.1
BROOKS		3	9.5
CALAIS		21	1.0
CAMPBELL-NAMAO		10	2.3
CASTOR		3	0.4
CHARLOTTE LAKE		2	0.4
COLD LAKE		2	0.4
CRAIG LAKE		1	0.3
DOWLING LAKE		1	0.3

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
DUVERNAY	1	0.6
EDWAND	3	0.1
ELK POINT	1	1.0
ELLERSLIE	1	0.1
ETZIKOM	15	1.7
EXCELSIOR	36	1.0
FENN-BIG VALLEY	1	0.8
FORT KENT	2	0.1
GLEN PARK	5	1.2
HAIRY HILL	11	0.6
HAMELIN CREEK	19	0.6
HANNA	11	2.5
HEART RIVER	3	0.1
HOLMBERG	22	1.3
KILLAM NORTH	19	0.9
KNOPCIK	13	1.0
LAC LA BICHE	7	1.0
LEAHURST	37	1.4
LEGAL	2	1.0
LINDBERGH	12	1.0
LLOYDMINSTER	2	0.5
MURIEL LAKE	5	0.4
NORMANDVILLE	39	5.0
OBERLIN	-	1.0
REDLAND	16	0.6
REDWATER	20	0.6
RYCROFT	12	1.6
SADDLE HILLS	52	5.5
STETTLER	2	2.1
ST. PAUL	-	0.8
STRATHMORE	16	2.5
STURGEON LAKE SOUTH	2	0.5
WATTS	2	0.9
WHITELAW	8	5.0

TABLE D-1 (continued)

Field	Marketable Gas at May 31, 1968 Bcf	Reserve-Delivery Ratio Bcf/MMcfd
Wildmere	17	1.0
Willingdon	13	0.7
Wizard Lake	3	0.5
Woking	12	0.9
TOTAL	661	
WEIGHTED AVERAGE		0.9
TOTAL RESERVES CONNECTED AND SUPPLYING REQUIREMENTS	6,457	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.6

TABLE D-2

SUMMARY OF RESERVES AND AVERAGE RESERVE-DELIVERY RATIO FOR ALL RESERVES IN THE PROVINCE

FIELD	MARKETABLE RESERVES AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
RESERVES NOW SUPPLYING ALBERTA'S REQUIREMENTS (SEE TABLE D-1)	6,457	2.6
FIELDS INCLUDED IN PERMITS (SEE TABLE D-3)	27,091	1.7
FIELDS APPLIED FOR BY TRANS-CANADA PIPE LINES LIMITED (SEE TABLE E-1)	1,830	8.1
REMAINING ESTABLISHED RESERVES (2)	8,207	1.9
TOTAL RECOVERABLE RESERVES IN THE PROVINCE	43,585	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.0

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

(2) INCLUDES DEFERRED RESERVES AND RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH.

TABLE D-3

MARKETABLE RESERVES AVAILABLE IN THE FIELDS INCLUDED IN PERMITS AND RESERVE-DELIVERY RATIOS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE GAS AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
ALBERTA AND SOUTHERN GAS CO. LTD. (PERMIT NO. AS 64-3)		
BIGSTONE	326	3.3
BRAZEAU RIVER	125	3.5
CAROLINE	33	1.1
CARSON CREEK	256	0.8
CARSON CREEK NORTH	175	24.2
CROSSFIELD	912	2.1
FERRIER	21	7.5
HARMATTAN-ELKTON	157	3.3
HOMEGLEN-RIMBEY	142	0.7
JUDY CREEK, SWAN HILLS, SWAN HILLS SOUTH AND VIRGINIA HILLS	170	39.8
KAYBOB	466	1.9
MARLBORO	40	5.1
MINNEHIK-BUCK LAKE	404	1.3
PEMBINA	103	4.9
PINE CREEK	122	1.5
PINE NORTH-WEST	237	6.8
SUNDRE	39	11.6
SYLVAN LAKE	7	2.3
WATERTON	1,280	2.4
WESTEROSE SOUTH	419	0.5
WESTWARD HO	-	-
WILDCAT HILLS	504	5.9
WILLESDEN GREEN	153	12.9
WILSON CREEK	55	2.2
WINDFALL	513	1.0
TOTAL	6,659	
WEIGHTED AVERAGE		1.8

---

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
ALBERTA AND SOUTHERN GAS CO. LTD. (PERMIT NO. AS 67-4)		
BELLOY	79	2.8
BERLAND RIVER	297	1.2
EAGLESHAM	67	4.6
FOX CREEK	124	1.5
GOLD CREEK	400	4.1
HUNTER VALLEY	20	3.0
KAYBOB SOUTH	910	3.8
PEMBINA	8	2.0
TANGENT	109	3.6
WASKAHIGAN	69	3.6
WILDHORSE CREEK	49	4.0
TOTAL	2,132	
WEIGHTED AVERAGE		2.8
CANADIAN-MONTANA PIPELINE COMPANY (PERMIT NO. CM 54-1 AND CM 61-2)		
ADEN	13	2.1
BLACK BUTTE	51	3.4
COMREY	14	1.9
KNAPPEN	16	2.0
MANYBERRIES	6	1.1
PAKOWKI LAKE	11	1.4
PENDANT D'OREILLE	120	2.0
SMITH COULEE	5	1.1
TOTAL	236	
WEIGHTED AVERAGE		1.9
TRANS-CANADA PIPE LINES LIMITED (PERMIT NO. TC 67-7)		
ABEE	7	2.7
ALDERSON	328	5.9
ATLEE-BUFFALO	93	2.6
BAPTISTE	16	0.9
BASHAW	34	0.3
BELLIS	41	0.9

TABLE D-3 (CONTINUED)

Field	MARKETABLE GAS AT MAY 31, 1968 Bcf	RESERVE-DELIVERY RATIO Bcf/MMcfd
Berry	11	2.5
Bindloss	240	3.4
Boyle	14	1.0
Brazeau River	522	2.9
Bruce	26	1.5
Calling Lake	37	1.5
Caroline	132	4.3
Carstairs	704	1.7
Cessford	1,024	2.1
Chigwell	33	1.3
Connorsville	60	3.8
Countess	177	0.7
Craigend	185	1.8
Crossfield	310	4.4
Crossfield East	759	3.8
Drumheller	70	1.2
Edson	2,030	2.0
Enchant	37	0.3
Equity	40	2.9
Erskine	41	1.6
Fenn-Big Valley	-	-
Fenn West	7	0.5
Figure Lake	32	0.9
Flat	124	4.9
Francis	6	5.3
Garrington	7	5.6
Ghost Pine	286	1.2
Gilby	715	1.5
Hackett	47	1.4
Hamilton Lake	29	5.6
Harmattan East	63	6.6
Harmattan-Elkton	41	0.8
Homeglen-Rimbey	426	0.7

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
Hussar	367	0.7
Innisfail	81	6.1
Jarrow	9	1.8
Killam	11	0.9
Little Bow	29	1.0
Lone Pine Creek	249	2.9
Long Coulee	13	0.3
Lookout Butte	468	4.6
Malmo	49	1.0
Marten Hills	837	1.9
Medicine Hat	303	5.7
Medicine River	282	3.4
Minnehik-Buck Lake	-	-
Nevis	697	1.8
New Norway	11	1.4
Olds	258	2.9
Oyen	35	3.2
Pincher Creek	305	12.2
Prevo	34	3.5
Princess	127	2.0
Provost	591	1.5
Retlaw	43	2.0
Rich	12	1.2
Rowley	76	2.5
Sedalia	97	11.6
Seiu Lake	27	6.0
Sibbald	25	2.1
Standard	20	5.4
Stettler	-	-
Sundre	12	3.3
Sunnynook	14	1.3
Swalwell	42	4.8
Sylvan Lake	494	2.6

TABLE D-3 (CONTINUED)

FIELD		MARKETABLE GAS AT MAY 31, 1968 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
THORHILD		11	2.5
THREE HILLS CREEK		167	4.2
TROCHU		5	3.5
TWINING NORTH		48	4.4
VERGER		70	1.1
VULCAN		32	1.6
WAYNE-ROSEDALE		189	1.0
WESTEROSE		79	21.0
WESTEROSE SOUTH		520	0.5
WIMBORNE		239	1.3
WINTERING HILLS		70	2.6
WOOD RIVER		25	1.9
	TOTAL	15,829	
	WEIGHTED AVERAGE		1.6
WESTCOAST TRANSMISSION COMPANY LIMITED (PERMIT NO. WC 59-3)			
CROSSFIELD		1,102	3.8
SAVANNA CREEK		175	14.3
	TOTAL	1,277	
	WEIGHTED AVERAGE		4.2
WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD. (PERMIT NO. WC 52-1 AND WC 62-5)			
BRAEBURN		62	4.2
GORDONDALE		18	1.4
POUCE COUPE		20	2.0
POUCE COUPE SOUTH		39	1.2
WORSLEY		15	0.4
	TOTAL	154	
	WEIGHTED AVERAGE		1.2
WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD. (PERMIT NO. WC 61-4)			
BOUNDARY LAKE SOUTH		35	0.9

TABLE D-3 (Continued)

FIELD	MARKETABLE GAS AT MAY 31, 1968 Bcf	RESERVE-DELIVERY RATIO Bcf/MMcfd
OTHERS		
Antelope	17	0.9
Esther	30	0.9
Halliday	3	1.4
Medicine Hat	680	2.3
Red Coulee	3	3.3
Richdale	18	1.8
Wildunn Creek	18	3.3
TOTAL	769	
WEIGHTED AVERAGE		2.1
TOTAL (All Fields)	27,091	
WEIGHTED AVERAGE (All Fields)		1.7

TABLE D-4

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS[1]

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT									EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVES IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD. (AS 64-3)	6,335	954	31/10/91	6,659					6,335	324	324
ALBERTA AND SOUTHERN GAS CO. LTD. (AS 67-4)	1,296	162	31/10/93	2,132					1,296	836	836
CANADIAN-MONTANA PIPE LINE COMPANY	236	97	15/3/86	236					236	-	-
TRANS-CANADA PIPE LINES LIMITED	14,980	2,257	31/10/92	15,829					14,980	849	849
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)	806	164	29/2/84	1,277	4.2	1.1	785	460	1,266	11	471
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	189	189	31/12/79	189					189	-	-
OTHERS	672	184		769				23	695	74	97
TOTALS	24,514	4,007		27,091				483	24,997	2,094	2,577
ROUNDED TOTALS	24,500	4,000		27,100				500	25,000	2,100	2,600

(1) ALL FIGURES ARE AS OF MAY 31, 1968.

(2) TRANS-CANADA DELIVERIES FROM THE CROSSFIELD RUNDLE B AND WABAMUN A POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS.

TABLE D-5

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS AS OF MARCH 31, 1968 AS ESTIMATED BY TRANS-CANADA

(All Volumes in Trillions of Cubic Feet at 1,000 BTU Per Cubic Foot)

Contractable Reserves					
Now considered within economic reach		41.1			
Less: Deferred		4.8			
Total Contractable Reserves				36.3	
Contractable Requirements					
Contractable Alberta Requirements			6.8		
Permit requirements –					
To meet commitments	25.3				
To meet terminal year peak	0.8				
			26.1		
Total contractable requirements				32.9	
Contractable Surplus					+3.4
Remaining Requirements					
Total Alberta Requirements for delivery	12.7				
Alberta requirements for thirtieth year peak	5.4				
Total Alberta requirements			18.1		
Less: Available from contractable reserves			6.8		
Total Remaining requirements				11.3	
Remaining and Future Reserves					
From Deferred gas available within the 30-year period			4.2		
From Release of reserves 'required' to protect Peak day in permits			0.8		
From reserves which will become within economic reach during the 30 year period			2.1		
From appreciation of established reserves and future discoveries			5.2		
				12.3	
Future Surplus					+1.0
Overall Surplus					+4.4

TABLE D-6

CPA PROBABLE MARKETABLE GAS RESERVES

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS AS OF DECEMBER 31, 1967

(All Volumes in Trillions of Cubic Feet at 1,000 BTU Per Cubic Foot)

Contractable Reserves				
Now considered within economic reach		40.2		
Empress Plant shrinkage		0.4		
Less: deferred		4.9		
Total contractable			35.7	
Contractable Requirements				
Contractable Alberta requirements		6.8		
Permit requirements –				
To meet commitments	25.3			
To meet terminal year peak	0.8			
		26.1		
Total contractable requirements			32.9	
CONTRACTABLE SURPLUS				+2.8
Remaining requirements				
Total Alberta requirements for delivery	12.7			
Alberta requirements for thirtieth year peak	5.4			
Total Alberta requirements		18.1		
Less: Available from contractable reserves		6.8		
Total Remaining requirements			11.3	
Remaining and Future Reserves				
From deferred gas available within 30 years		4.3		
From reserves now considered beyond economic reach		1.7		
From 2 years trends		5.0		
Total remaining and future reserves			11.0	
FUTURE SURPLUS				–0.3
Overall Surplus				
Before release of reserves required to protect peak day in permits				+2.5
After release of reserves required to protect peak day in permits				+3.3

TABLE D-7

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF MAY 31, 1968

AS ESTIMATED BY THE BOARD

(All Volumes in Trillions of Cubic Feet at 1000 Btu Per Cubic Foot)

CONTRACTABLE RESERVES					
Now Considered Within Economic Reach			40.7		
Less: Deferred			6.0		
Total Contractable Reserves				34.7	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta Requirements			7.4		
Permit Requirements:					
To meet commitments		24.5			
To meet terminal year peak day		0.5			
Total Contractable Requirements				32.4	
CONTRACTABLE SURPLUS					2.3
REMAINING REQUIREMENTS					
Total Alberta Requirements For Delivery	14.5				
Less: Deliveries From Contractable Reserves	5.6				
Deliveries Required From Other Sources		8.9			
Total Alberta Requirements for Thirtieth Year Peak Day	5.0				
Less: Available From Contractable Reserves	1.8				
Required from Other Sources To Meet Thirtieth Year Peak Day		3.2			
Total Remaining Requirements			12.1		
REMAINING AND FUTURE RESERVES					
From Deferred Gas Available Within 30 Years		5.3			
From Reserves Now Considered Beyond Economic Reach		2.2			
From 2 Years Trends		5.0			
Total Remaining and Future Reserves			12.5		
FUTURE SURPLUS					0.4
OVERALL SURPLUS					
Before Release of Reserves Required to Protect Peak Day in Permits					2.7
After Release Of Reserves Required To Protect Peak Day In Permits					3.2

TABLE D-8

DEFERRED RESERVES

(All Volumes at 1000 Btu Per Cubic Foot)

Pool	Marketable Reserve at May 31, 1968 Bcf	
Marketable within 30 Years		
Bantry Mannville A	28	
Clive D-2 & D-3	42	
Excelsior Mannville A	32	
Harmattan East Rundle	1,049	
Harmattan-Elkton Rundle	1,062	
Joarcam Viking	52	
Kaybob Cadomin B	64	
Kaybob South Beaverhill Lake A	763	
Leduc-Woodbend Blairmore	46	
Leduc-Woodbend D-2A	47	
Leduc-Woodbend D-3A	381	
Pembina Cardium	113	
Swalwell Pekisko	39	
Sylvan Lake Jurassic A	30	
Windfall	378	
Other Reserves	1,176	
		5,302
Deferred Beyond 30 Years		
Bonnie Glen D-3A	378	
Golden Spike D-3A	209	
Westerose D-3	102	
		689
Total Deferred Reserves		5,991

APPENDIX E

THE APPLICATION FOR AUTHORIZATION FOR THE REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE EFFECT THE AUTHORIZATION WOULD HAVE ON SURPLUS

Trans-Canada is now authorized under its permit to remove from the Province 17,100 billion cubic feet of gas, of which some 2,700 billion cubic feet had been removed to May 31, 1968. It applied for an increase of 2,100 billion cubic feet in the quantity authorized, which would increase the total to 19,200 billion cubic feet of gas, at a maximum daily rate of 2,715 million cubic feet, from the fields now named in its permit and from 35 new fields and areas. The volumes before and after adjustment to the basis of 1,000 Btu per cubic foot are compared below:

	As is Basis	1,000 Btu Basis
Total Trans-Canada permit volume, May 31, 1968, Bcf	17,100	17,784
Addition applied for, Bcf	2,100	2,184
Trans-Canada permit volume if the application is granted, Bcf	19,200	19,968
Removed at May 31, 1968, Bcf	2,696	2,804
Remaining Trans-Canada permit volumes if the application is granted, Bcf	16,504	17,164
Present maximum daily rate, Mmcfd	2,170	2,257
Maximum daily rate applied for, MMcfd	2,715	2,824

All volumes subsequently referred to in this Appendix respecting the Trans-Canada permit are on the basis of 1,000 Btu per cubic foot.

Trans-Canada has applied for an increase of its remaining authorized withdrawals from 14,980 as of May 31, 1968, to 17,164 billion cubic feet (17,784 - 2,804 = 14,980). Table E-1 shows proposed additions and deletions of fields in the Trans-Canada permit as well as the Board's current estimate of the remaining reserves of marketable gas and the reserve-delivery ratio for each of the fields listed. Two of the fields from which Trans-Canada proposes to remove part of the gas reserves are Hunter Valley and Wildhorse Creek where Alberta and Southern already has approval to remove some gas reserves.

As shown in Table E-1 eight fields with marketable gas reserves totalling 77 billion cubic feet are being deleted from the permit since Trans-Canada no longer has gas under contract in them. The reasons for the deletions are discussed more fully in Sections IV and V.

The results of the Board's analysis with respect to the meeting of permit commitments and the additional volumes applied for by Trans-Canada are presented in Table E-2, which is identical in form to the previously discussed Table D-4. In fact the only changes have been to replace the Trans-Canada entry with a new entry reflecting the additional quantities applied for and reserves available in the fields from which the applicant proposes to remove gas.

The Trans-Canada entry in the table suggests that the remaining volume applied for of 17,164 billion cubic feet is less than the Board's estimate of total reserves of fields which would be included in Trans-Canada's permit of 17,659 billion cubic feet. Westcoast has first right to delivery from the Crossfield pools being processed at the Petrogas Processing Ltd. facility for the duration of its contract, but Trans-Canada has under contract any additional volumes, up to a maximum of some 360 billion cubic feet, available after satisfying the Westcoast contract. This gas will likely be partly available during the term of the Westcoast permit and at least part would be available following termination of the Westcoast permit; hence, 300 billion cubic feet have been included in Column 4 of Table D-2 as reserves in permit fields available to Trans-Canada. Alberta and Southern has first priority for delivery in the Hunter Valley and Wildhorse Creek Fields but for reasons similar to those stated above for Crossfield, portions of the reserves have been assigned to Trans-Canada.

Since Alberta's requirements and the other permit volumes can be separately accommodated from other Alberta reserves, the Board believes the entire amounts applied for may be included in the quantity approved for removal from the Province. However, no assurance can be given that the gas can be produced during the full term of the permits at the respective requested maximum daily rates.

Table E-2 further shows that, with the inclusion of the volumes applied for by Trans-Canada, the remaining permit commitments would total some 26.7 trillion cubic feet and the reserves required to meet these commitments would total some 27.2 trillion cubic feet.

Table E-3 presents the calculation of the amount of gas that would be surplus to Alberta's requirements and the permit commitments if the application of Trans-Canada is granted. Most of the figures used in the preparation of the table have been taken directly from Table D-7.

On the basis of the Board's estimates, there would be a modest contractable surplus of 0.1 trillion cubic feet if Trans-Canada were authorized to remove the additional volumes applied for. The table also shows that the remaining and future reserves would exceed the remaining requirements by 0.4 trillion cubic feet. The overall surplus before release of reserves allocated to protect peak day requirements in certain permits where such protection applies would be 0.5 trillion. After release, at the end of the term of the permits, of the 0.5 trillion cubic feet of gas allocated to protect peak day requirements in permits, an overall surplus of 1.0 trillion cubic feet would exist.

TABLE E-1

PROPOSED CHANGES IN MARKETABLE RESERVES AND FIELDS IN THE TRANS-CANADA PERMIT

(All Volumes At 1000 Btu Per Cubic Foot)

FIELDS	MARKETABLE GAS AT MAY 31, 1968 Bcf	RESERVE-DELIVERY RATIO Bcf/MMcfd
Fields Trans-Canada Applied to have Added to Permit		
Alderson	17	4.4
Amisk	7	2.5
Armada	14	2.2
Bassano	9	0.9
Big Bend	67	3.2
Black Diamond	19	5.0
Blueridge	19	1.9
Burnt Timber	257	15.0
Cassils	9	5.6
Castor	7	2.4
Chestermere	25	6.0
Countess	17	2.7
Ferrier	303	7.3
Goodwin	16	4.0
Greencourt	108	6.3
Hamilton Lake	6	7.5
Hughenden	5	4.4
Hunter Valley	30	4.4
Jumping Pound West	69	5.9
Lathom	3	1.3
Leckie	1	0.7
Little Bow	1	1.0
Long Coulee	3	1.3
McMullen	7	1.1
Mitsue	187	31.7
Newell	2	0.5
Pelican	9	2.7
Quirk Creek	495	26.4
Rainier	3	0.7

Field	Marketable Gas at May 31, 1968 Bcf	Reserve-Delivery Ratio Bcf/MMcfd
Retlaw	41	4.9
Scandia	4	2.9
Sedgewick	26	1.8
Turin	28	2.0
Whitecourt	45	1.5
Wildhorse Creek	48	4.7
TOTAL	1,907	
WEIGHTED AVERAGE		6.8
Fields to be deleted from Permit		
Abee	7	2.7
Baptiste	16	0.9
Calling Lake	37	1.5
Fenn-Big Valley	-	-
Francis	6	5.3
Minnehik-Buck Lake	-	-
Stettler	-	-
Thorhild	11	2.5
TOTAL	77	
WEIGHTED AVERAGE		1.5
NET TOTAL	1,830	
NET WEIGHTED AVERAGE		80.1

TABLE E-2

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS INCLUDING THE TRANS-CANADA APPLICATION (1)

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT									EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVES IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD. (AS 64-3)	6,335	954	31/10/91	6,659					6,335	324	324
ALBERTA AND SOUTHERN GAS CO. LTD. (AS 67-4)	1,296	162	31/10/93	2,132					1,296	836	836
CANADIAN-MONTANA PIPELINE COMPANY	236	97	15/3/86	236					236	-	-
TRANS-CANADA PIPE LINES LIMITED	17,164	2,824	31/10/93	17,659					17,164	495	495
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)	806	164	29/2/84	1,277	4.2	1.1	785	460	1,266	11	471
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	189	189	31/12/79	189					189	-	-
OTHERS	672	184		769				23	695	74	97
TOTALS	26,698	4,574		28,921				483	27,181	1,740	2,223
ROUNDED TOTALS	26,700	4,600		28,900				500	27,200	1,700	2,200

(1) ALL VOLUMES ARE AS OF MAY 31, 1968, EXCEPT FOR THE ADJUSTMENTS FOR THE TRANS-CANADA APPLICATION.

(2) TRANS-CANADA DELIVERIES FROM THE CROSSFIELD RUNDLE B AND WABAMUN A POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS. SIMILARLY TRANS-CANADA DELIVERIES FROM HUNTER VALLEY AND WILDHORSE CREEK ARE DEPENDENT ON THE EXISTENCE OF DELIVERABILITY FROM THESE FIELDS SURPLUS TO THAT REQUIRED BY ALBERTA AND SOUTHERN.

TABLE E-3

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF MAY 31, 1968

AS ESTIMATED BY THE BOARD

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES				
Now Considered Within Economic Reach			40.7		
Less: Deferred			6.0		
Total Contractable Reserves				34.7	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta Requirements			7.4		
Permit Requirements - To Meet Commitments		26.7			
- To Meet Terminal Year Peak Day		0.5			
Total Contractable Requirements				34.6	
CONTRACTABLE SURPLUS					0.1
REMAINING REQUIREMENTS					
Total Alberta Requirements For Delivery	14.5				
Less: Deliveries From Contractable Reserves	5.6				
Deliveries Required From Other Sources		8.9			
Total Alberta Requirements for Thirtieth Year Peak Day	5.0				
Less: Available From Contractable Reserves	1.8				
Required From Other Sources to Meet Thirtieth Year Peak Day		3.2			
Total Remaining Requirements			12.1		
REMAINING AND FUTURE RESERVES					
From Deferred Gas Available Within 30 Years		5.3			
From Reserves Now Considered Beyond Economic Reach		2.2			
From 2 Years Trends		5.0			
Total Remaining and Future Reserves			12.5		
FUTURE SURPLUS					0.4
OVERALL SURPLUS					
Before Release Of Reserves Required To Protect Peak Day In Permits					0.5
After Release Of Reserves Required To Protect Peak Day In Permits					1.0

APPENDIX F

IN THE MATTER of The Gas Resources Preservation Act, 1956, being Chapter 19 of the Statutes of Alberta, 1956; and

IN THE MATTER of a Permit to Trans-Canada Pipe Lines Limited authorizing the removal of gas from the Province.

PERMIT No. TC 68-8

WHEREAS Trans-Canada Pipe Lines Limited (herein called "the Permittee") is removing gas from the Province under the authority of Permit No. TC 67-7; and

WHEREAS the Permittee has applied to the Oil and Gas Conservation Board for an increase in the volumes of gas that it may remove or cause to be removed from the Province, and for amendment and consolidation of its permit; and

WHEREAS the Board upon inquiry into and hearing of the application has found that the Permittee is a person who appears to have made arrangements to purchase gas within the Province and who proposes to remove such gas from the Province and that the provisions of The Gas Resources Preservation Act, 1956, affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of this Permit for the removal of gas from the Province is in the public interest having regard to the present and future needs of persons within the Province and to the established reserves and the trends in growth and discovery of reserves of gas in the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council, numbered O.C. /68, and dated

THEREFORE, the Oil and Gas Conservation Board, pursuant to the provisions of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956, hereby grants a permit to Trans-Canada Pipe Lines Limited, and hereby authorizes the removal of gas from the Province, subject to the regulations and orders made pursuant to the provisions of the said Act and to the terms and conditions prescribed in this Permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this Permit shall be operative for a term commencing on the date hereof and ending on October 31, 1993.

2. The quantity of gas that may be removed from the Province pursuant to this Permit shall not exceed

(a) during the term of the Permit and together with gas removed under Permit No. TC 54-1, Permit No. TC 59-2, Permit No. TC 60-3, Permit No. TC 60-4, Permit No. TC 64-5, Permit No. TC 64-6 and Permit No. TC 67-7, 19,200,000,000,000 cubic feet, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending October 31, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 2,715,000,000 cubic feet and in a 12-month period such rates shall not exceed 860,000,000,000 cubic feet.

3. The quantity of gas that may be removed from the Province, in accordance with clause 2, subclause (b), during any 12-month period ending October 31, may be augmented by any part of the quantity by which gas removed from the Province under this Permit, Permit No. TC 54-1, Permit No. TC 59-2, Permit No. TC 60-3, Permit No. TC 60-4, Permit No. TC 64-5, Permit No. TC 64-6 or Permit No. TC 67-7, in the last preceding four-year period ending October 31, shall have been less than the quantity authorized by the permit or permits to be so removed in the four-year period and which has not, in the meantime, been removed from the Province as an augmentation authorized by this clause, but nothing herein authorizes the removal of gas from the Province in any consecutive 24-hour period or during the term of the Permit in excess of the volumes stipulated for such periods in clause 2.

4. Notwithstanding the provisions of clause 2, subclause (b), the Permittee, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized by said subclause (b).

5. The Permittee, for the purpose of this Permit, may purchase or otherwise acquire for removal from the Province, and subject to clause 8 there may be removed from the Province under the authority of this Permit, only gas produced from the following pools, fields and areas:

Alderson Field

Amisk Field

Armada Field

Atlee-Buffalo Field

Bashaw Field

Bassano Field

Bellis Field

Berry Field

Big Bend Field

Bindloss Field

Black Diamond Field

Blue Ridge Field

Boyle Field

Brazeau River Field

Bruce Field

Burnt Timber Field

Caroline Viking A Pool

Caroline Viking E Pool

Caroline Basal Mannville A Pool

Carstairs Field

Cassils Field

Castor Field

Cessford Field

Chestermere Field

Chigwell Field

Connorsville Field

Countess Field

Craigend Field

Crossfield Field

Crossfield East Field

Drumheller Field

Edson Field

Enchant Field

Equity Field

Erskine Field

Fenn West Field

Ferrier Field

Figure Lake Field

Flat Field

Garrington Mannville A Pool

Garrington Leduc A Pool

Ghost Pine Field

Gilby Field

Goodwin Field

Greencourt Field

Hackett Field

Hamilton Lake Field

Harmattan East Field

Harmattan-Elkton Rundle A Pool

Homeglen-Rimbey Field

Hughenden Field

Hunter Valley Field

Hussar Field

Innisfail Field

Jarrow Field

Jumping Pound West Field

Killam Field

Lathom Field

Leckie Field

Little Bow Field

Lone Pine Creek Field

Long Coulee Field

Lookout Butte Field

Malmo Field

Marten Hills Field

McMullen Field

Medicine River Field

Mitsue Field

Nevis Field

Newell Field

New Norway Field

Olds Field

Oyen Field

Pelican Field

Pincher Creek Field

Prevo Field

Princess Field

Provost Field

Quirk Creek Field

Rainier Field

Retlaw Field

Rich Field

Rowley Field

Scandia Field

Sedalia Field

Sedgewick Field

Seiu Lake Field

Sibbald Field

Standard Field

Sundre Basal Mannville A Pool

Sundre Basal Mannville B Pool

Sunnynook Field

Swalwell Field

Sylvan Lake Field

Three Hills Creek Field

Trochu Field

Turin Field

Twining North Field

Verger Field

Vulcan Field

Wayne-Rosedale Field

Westerose Field

Westerose South Field

Whitecourt Field

Wildhorse Creek Field

Wimborne Field

Wintering Hills Field

Wood River Field

The area in the Medicine Hat Field being north of Section 1 to 6 inclusive, in Township 15, and in Ranges 1 to 3 inclusive, West of the 4th Meridian, excepting therefrom Section 7, Township 15, Range 2, West of the 4th Meridian.

6. (1) The Permittee shall satisfy the Board prior to November 1, 1970, or such later date as the Board upon application by the Permittee may stipulate, that

(a) the Permittee has entered into gas purchase contracts to purchase gas from the Bruce Field, the Flat Field, the Jarrow Field and the Killam Field or from a substantial part of each of the fields; and

(b) the Permittee has elected to cause the construction of the Bruce-Birch Lake Line or has advised the sellers under the contracts referred to in subclause (a) that it is proceeding to cause the Marten Hills Line to be constructed; and

(c) arrangements have been completed for construction of facilities necessary for the transportation of gas produced from the said fields and that effective removal of gas produced from the said fields shall commence on or before February 1, 1971, unless upon application by the Permittee a later date is stipulated by the Board.

(2) If the Permittee fails to satisfy the Board at the time and regarding the matters set out in subclause (1), the Board may, at a public hearing, reconsider the circumstances and may delete from this Permit any or all of the fields referred to in subclause (1) and reduce the volumes referred to in clause 2 accordingly.

7. (1) The Permittee shall satisfy the Board prior to November 1, 1971, or such later date as the Board upon application by the Permittee may stipulate, that

(a) the Permittee has entered into gas purchase contracts to purchase gas from the Amisk Field, Big Bend Field, Black Diamond Field, Castor Field, Chestermere Field, Hamilton Lake Field, Hughenden Field, Jumping Pound West Field, McMullen Field, Pelican Field, Provost Field and Turin Field or from a substantial part of each of the fields; and

(b) arrangements have been completed for construction of facilities necessary for the transportation of gas produced from the said fields and that effective removal of gas produced from the said fields shall commence on or before February 1, 1972, unless upon application by the Permittee a later date is stipulated by the Board.

(2) If the Permittee fails to satisfy the Board at the time and regarding the matters set out in subclause (1), the Board may, at a public hearing, reconsider the circumstances and may delete from this Permit any or all of the fields referred to in subclause (1) and reduce the volumes referred to in clause 2 accordingly.

8. Gas acquired in Alberta by the Permittee, in exchange for equal volumes of gas, adjusted for any difference in higher heating value, produced from pools, fields or areas named in clause 5, may be removed from the Province under the authority of this Permit.

9. The Permittee shall remove or cause to be removed pursuant to this Permit only such gas as is delivered to it through facilities of The Alberta Gas Trunk Line Company Limited at the interconnections of their pipe lines in the North-east quarter of Section 11, Township 20, Range 1, West of the 4th Meridian and in the North-east quarter of Section 11, Township 38, Range 1, West of the 4th Meridian.

10. (1) All gas removed from the Province pursuant to this Permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located at the points at

which gas is delivered in accordance with clause 9 by The Alberta Gas Trunk Line Company Limited to the Permittee.

(2) The specific gravity and higher heating value of all gas received by the Permittee through the facilities of The Alberta Gas Trunk Line Company Limited shall be measured by or on behalf of the Permittee at the points at which gas is delivered by The Alberta Gas Trunk Line Company Limited to the Permittee.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

11. Subject to section 14 of the said Act, all quantities of gas for the purpose of this Permit shall be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

12. Notwithstanding the provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this Permit.

13. The Permittee will supply gas from the pipe line of The Alberta Gas Trunk Line Company Limited at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas for such a community or consumer, that is willing to take delivery of gas at a point on the pipe line, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

14. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 13, and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

15. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, competent regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

16. Permit No. TC 67-7 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this day of , A.D. 1968.

OIL AND GAS CONSERVATION BOARD

G. W. Govier

Chairman